YEAR 2002

ANNUAL REPORT
OF

Montana-Dakota Utilities Company

GAS UTILITY

TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

Gas Annual Report

Instructions

General

1. A Microsoft EXCEL 2000 workbook of the annual report is being provided on computer disk for your convenience. The workbook contains the schedules of theannual report. Each schedule is on the worksheet named that schedule. For example, Schedule 1 is on the sheet titled "Schedule 1". By entering your company name in the cell named "Company" of the first worksheet, the spreadsheet will put your company name on all the worksheets in the workbook. The same is true for inputting the year of the report in the cell named "YEAR". You can "GOTO" the proper cell by using the F5 key and selecting the name of the cell.

2. The workbook contains input sections that are unprotected, and non-input sections that are protected. Cell protection can be disabled or enabled through "TOOLS – PROTECTION – UNPROTECT SHEET" on your toolbar. Formulas and checks are built into most of the templates.

3. Use of the disk is optional. The disk and the report cover shall be returned when the report is filed. There are macros built into the workbook to assist you with the report. An explanation of the macros is on the "Control" worksheet at the front of the workbook. The explanations start at cell A1.

4. All forms must be filled out in permanent ink and be legible. Note: Even if the computer disk is used, a printed version of the report shall be filed. **Please submit one unbound copy of the annual report along with the regular number of annual reports that you submit**. This aids in scanning the report so that it may be published on our web site. The orientation and margins are set up on each individual worksheet and should print on one page. If you elect not to use the disk, please format your reports to fit on one 8.5'' by 11'' page with the left binding edge (top if landscaped) set at .85'', the right edge (bottom if landscaped) set at .4", and the remaining two margins at .5''. You may select specific schedules to print – See the worksheet "CONTROL".

5. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses ( ).

6. Where space is a consideration, information on financial schedules may be rounded to thousands of dollars. Companies submitting schedules rounded to thousands shall so indicate at the top of the schedule.

7. Where more space is needed or more than one schedule is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains and be labeled accordingly (for example, Schedule 1A).

8. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.
9. All companies owned by another company shall attach a corporate structure chart of the holding company.

10. Schedules that have no activity during the year or are not applicable to the respondent shall be marked as not applicable and submitted with the report.

11. The following schedules shall be filled out with information on a total company basis:

    Schedules 1 through 5
    Schedules 6 and 7
    Schedule 14
    Schedule 17 and 18
    Schedules 23 through 26
    Schedule 33

    All other schedules shall be filled out with either Montana specific data, or both total company and Montana specific data, as indicated in the schedule titles and headings.

    Financial schedules shall include all amounts originating in Montana or allocated to Montana from other jurisdictions.

12. For schedules where information may be provided using Mcf or Dkt, circle Mcf or Dkt to indicate which measurement is being reported. (For example, schedules 28, 32, 33 and 34).

13. FERC Form-2 sheets may not be substituted in lieu of completing annual report schedules.

14. Common sense must be used when filling out all schedules.

Specific Instructions

Schedules 6 and 7

1. All transactions with affiliated companies shall be reported. The definition of affiliated companies as set out in 18 C.F.R. Part 201 shall be used.

2. Column (c). Respondents shall indicate in column (c) the method used to determine the price. Respondents shall indicate if a contract is in place between the Affiliate and the Utility. If a contract is in place, respondents shall indicate the year the contract was initiated, the term of the contract and the method used to determine the contract price.

3. Column (c). If the method used to determine the price is different than the previous year, respondents shall provide an explanation, including the reason for the change.

Schedules 8, 18, and 23

1. Include all notes to the financial statements required by the FERC or included in the financial statements issued as audited financial statements. These notes shall be included in the report directly behind the schedules and shall be labeled appropriately (Schedule 8A, etc.).

Schedule 12

1. Respondents shall disclose all payments made during the year for services where the aggregate payment to the recipient was $5,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall report aggregate payments of $25,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall report aggregate payments of $75,000 or more. Payments must include fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payment for services or as a donation.

Schedule 14

1. Companies with more than one plan (for example, both a retirement plan and a deferred savings plan) shall complete a schedule for each plan.

2. Companies with defined benefit plans must complete the entire form using FASB 87 and132 guidelines.

3. Interest rate percentages shall be listed to two decimal places.

Schedule 15

1. All changes in the employee benefit plans shall be explained in a narrative on lines 15 and 16. All cost containment measures implemented in the reporting year shall be explained and quantified in a narrative on lines 15 and 16. All assumptions used in quantifying cost containment results shall be disclosed.

2. Schedule 15 shall be filled out usingFASB 106 and 132 guidelines.

Schedule 16

1. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

2. The above compensation items shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

Schedule 17

1. Respondents shall provide all executive compensation information in conformance with that required by the Securities and Exchange Commission (SEC) (Regulation S-K Item 402, Executive Compensation).

2. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

3. All items included in the "other" compensation column shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

4. In addition, respondents shall attach a copy of the executive compensation information provided to the SEC.

Schedule 24

1. Interest expense and debt issuance expense shall be included in the annual net cost column.

Schedule 26

1. Earnings per share and dividends per share shall be reported on a quarterly basis and entries shall be made only to the months that end the respective quarters (for example, March, June, September, and December.)

2. The retention and price/earnings ratios shall be calculated on a year end basis. Enter the actual year end market price in the "TOTAL Year End" row. If the computer disk is used, enter the year end market price in the "High" column.

Schedule 27

1. All entries to lines 9 or 16 must be detailed separately on an attached sheet.

2. Only companies who have specifically been authorized in a Commission Order to include cash working capital in ratebase may include cash working capital in lines 9 or 16. Cash working capital must be calculated using the methodology approved in the Commission Order. The Commission Order specifying cash working capital shall be noted on the attached sheet.

2. Indicate, for each adjustment on lines 28 through 46, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

Schedule 28

1. Information from this schedule is consolidated with information from other Utilities and reported to the National Association of Regulatory Utility Commissioners (NARUC). Your assistance in completing this schedule, even though information may be located in other areas of the annual report, expedites reporting to the NARUC and is appreciated.

Schedule 31

1. This schedule shall be completed for the year following the reporting year.

2. Respondents shall itemize projects of $50,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall itemize projects of $100,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall itemize projects of $1,000,000 or more. All projects that are not itemized shall be reported in aggregate and labeled as Other.

Schedule 34

1. In addition to a description, the year the program was initiated and the projected life of the program shall be included in the program description column.

2. On an attached sheet, define program "participant" and program conservation "unit" for each program. Also, provide the number of program participants and the number of units acquired or processed during this reporting year.

Gas Annual Report

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IDENTIFICATION

Year: 2002

1.	Legal Name of Respondent:	MDU Resources Group, Inc.
2.	Name Under Which Respondent Does Business:	Montana-Dakota Utilities Co.
3.	Date Utility Service First Offered in Montana	1920
4.	Address to send Correspondence Concerning Report:	Montana-Dakota Utilities Co. 400 North Fourth Street Bismarck, ND 58501
5.	Person Responsible for This Report:	Donald R. Ball
5a.	Telephone Number:	(701) 222-7630

Control Over Respondent

1. If direct control over the respondent was held by another entity at the end of year provide the following:

   1a. Name and address of the controlling organization or person:

   1b. Means by which control was held:

   1c. Percent Ownership:

SCHEDULE 2

Board of Directors 1/

Line No.	Name of Director and Address (City, State) (a)	Remuneration (b)
1	Martin A. White, Bismarck, ND	-
2	Ronald D. Tipton, Bismarck, ND	-
3	C. Wayne Fox, Bismarck, ND	-
4	Lester H. Loble II, Bismarck, ND	-
5	Bruce T. Imsdahl, Bismarck, ND	-
6	Ronald G. Skarphol, Bismarck, ND	-
7	Douglas C. Kane, Bismarck, ND 2/	-
8	Warren L. Robinson, Bismarck, ND	-
9		
10		
11	1/ Montana-Dakota Utilities Co. is a division of MDU Resources Group, Inc.,	
12	and has no Board of Directors. The affairs of the company are managed by	
13	a Managing Committee, the members of which are provided herein rather	
14	than the directors of MDU Resources Group, Inc.	
15	2/ Douglas C. Kane resigned his position on the Managing Committee	
16	effective 10/31/02.	

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 3**

Officers

Year: 2002

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	Chief Executive Officer	Executive	Ronald D. Tipton
3	President	Executive	C. Wayne Fox
5	Vice President	Energy Supply	Bruce T. Imsdahl [1/]
7	Executive Vice President	Business Development and Strategic Planning	Dennis L. Haider
10	Vice President	Operations	David L. Goodin
12	Vice President, Controller and Chief Accounting Officer	Accounting and Information Systems	Craig A. Keller
16	Vice President	Human Resources	Richard D. Spratt
18	Assistant Vice President	Gas Supply	Donald F. Klempel
20	Assistant Vice President	Regulatory Affairs	Donald R. Ball [2/]

22 [1/] Effective 2/5/2003, Bruce T. Imsdahl assumed the title of Executive Vice President.

24 [2/] Effective 2/5/2003, Donald R. Ball assumed the title of Assistant Vice President.

CORPORATE STRUCTURE

Year: 2002

Subsidiary/Company Name	Line of Business	Earnings (000's)	Percent of Total
Montana-Dakota Utilities Co./ Great Plains Natural Gas Co. (Divisions of MDU Resources Group, Inc.)	Electric and Natural Gas Distribution	$19,367	13.11%
WBI Holdings, Inc.	Pipeline and Energy Services and Natural Gas and Oil Production	72,289	48.95%
Knife River Corporation	Construction Materials and Mining	48,702	32.98%
Utility Services, Inc.	Utility Services	6,371	4.31%
Centennial Holdings Capital Corp./ MDU Resources International, Inc.	Independent Power Production	959	0.65%
TOTAL		$147,688	100.00%

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 5

CORPORATE ALLOCATIONS - GAS

Year: 2002

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	$1,789	3.14%	$55,211
2						
3	Advertising	Administrative & General	Various Corporate Overhead Allocation Factors,	1,575	3.03%	50,432
4			and/or Actual Costs Incurred			
5						
6	Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time	4,602	2.46%	182,447
7			Studies, and/or Actual Costs Incurred			
8						
9	Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time	974	4.66%	19,906
10			Studies, and/or Actual Costs Incurred			
11						
12	Bank Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or	11,674	3.14%	360,294
13			Actual Costs Incurred			
14						
15	Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time	3,369	3.02%	108,309
16			Studies, and/or Actual Costs Incurred			
17						
18	Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	43,125	5.25%	778,698
19			Actual Costs Incurred			
20						
21	Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or	42,526	3.86%	1,058,864
22			Actual Costs Incurred			
23						
24	Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor Based on a	30,760	3.04%	980,925
25			Combination of Net Plant Investment and Number of			
26			Employees			
27						
28	Employee Benefits	Administrative & General	Corporate Overhead Allocation Factor Based on	5,796	3.15%	177,970
29			Number of Employees			

CORPORATE ALLOCATIONS - GAS

Year: 2002

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Employee Meetings	Administrative & General	Various Corporate Overhead Allocation Factors and/or	4,721	3.15%	145,232
2			Actual Costs Incurred			
3						
4	Employee Reimbursable	Administrative & General	Various Corporate Overhead Allocation Factors, Time	7,577	2.94%	250,012
5	Expenses		Studies, and/or Actual Costs Incurred			
6						
7	Express Mail	Administrative & General	Various Corporate Overhead Allocation Factors and/or	11	2.68%	399
8			Actual Costs Incurred			
9						
10	Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	34,594	3.18%	1,054,641
11			Actual Costs Incurred			
12						
13	Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time	56	3.15%	1,720
14			Studies, and/or Actual Costs Incurred			
15						
16	Meals & Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time	4,924	3.26%	146,287
17			Studies, and/or Actual Costs Incurred			
18						
19	Moving Expense	Administrative & General	Various Corporate Overhead Allocation Factors, Time	41	3.13%	1,268
20			Studies, and/or Actual Costs Incurred			
21						
22	Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time	3,530	3.70%	91,906
23			Studies, and/or Actual Costs Incurred			
24						
25	Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or	3,129	3.19%	94,824
26			Actual Costs Incurred			
27						
28	Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and	22,863	2.01%	1,112,973
29			Allocation Factors Based on Actual Experience			

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 5**

CORPORATE ALLOCATIONS - GAS

Year: 2002

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	323	3.10%	10,107
2			Actual Costs Incurred			
3						
4	Postage	Administrative & General	Various Corporate Overhead Allocation Factors and/or	722	3.16%	22,096
5			Actual Costs Incurred			
6						
7	Payroll	Administrative & General	Various Corporate Overhead Allocation Factors, Time	307,857	3.28%	9,079,470
8			Studies, and/or Actual Costs Incurred			
9						
10	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or	481	6.88%	6,515
11			Actual Costs Incurred			
12						
13	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or	3,661	3.22%	110,173
14			Actual Costs Incurred			
15						
16	Seminars & Meeting	Administrative & General	Various Corporate Overhead Allocation Factors, Time	3,943	3.23%	117,965
17	Registrations		Studies, and/or Actual Costs Incurred			
18						
19	Software Maintenance	Administrative & General	Various Corporate Overhead Allocation Factors, Time	2,656	3.13%	82,188
20			Studies, and/or Actual Costs Incurred			
21						
22	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors, Time	2,661	3.13%	82,296
23			Studies, and/or Actual Costs Incurred			
24						
25	**TOTAL**			$549,940	3.29%	$16,183,128

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 6**

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**KNIFE RIVER CORPORATION**	Expense	Actual Costs Incurred			
2		Air Service		$288		$82
3		Materials		6,385		6,385
4		Software Maintenance		47,989		12,755
5						
6		Capital	Actual Costs Incurred			
7		Materials		10,193		
8		Other Reimbursables		11		
9						
10						
11						
12						
13						
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16						
17						
18						
19						
20						
21		Total Knife River Corporation Operating Revenues for the Year 2002			$962,312,695	
22						
23						
24						
25	**TOTAL**	**Grand Total Affiliate Transactions**		$64,866	0.0067%	$19,222

Company Name: Montana-Dakota Utilities Co. SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**WBI HOLDINGS, INC**	Natural Gas	Actual Costs Incurred			
2		Purchases/Transportation		$55,013,796		$16,356,322
3						
4						
5						
6		Expense	Actual Costs Incurred			
7		Contract Services		6,972		1,109
8		Legal Fees		54,047		14,365
9		Materials		1,330		1,330
10		Employee Training		2,223		692
11		Office Supplies		1,963		611
12		Meals, Lodging & Other		73		23
13		Reference Materials		2,343		629
14		Miscellaneous		661		
15						
16		Capital	Actual Costs Incurred			
17		Other Reimbursables		1		
18		Materials		102		
19		WBI Subcontract Labor		192		
20		Vehicles		11,025		981
21						
22		Other Transactions/Reimbursements	Actual Costs Incurred			
23		Miscellaneous		26,576		
24		Auto Clearing		663		
25						
26						
27		Total WBI Operating Revenues for the Year 2002			$308,957,295	
28						
29						
30						
31	**TOTAL**	**Grand Total Affiliate Transactions**		$55,121,967	17.8413%	$16,376,062

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**UTILITY SERVICES, INC.**	Expense				
2		Contract Services	Actual Costs Incurred	$88,130		$149
3						
4						
5						
6						
7		Capital				
8		Contract Services	Actual Costs Incurred	3,097		314
9						
10						
11						
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27						
28		Total USI Operating Revenues for the Year 2002			$458,660,131	
29						
30						
31						
32	**TOTAL**	**Grand Total Affiliate Transactions**		$91,227	0.0199%	$463

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	**CENTENNIAL HOLDINGS**	Expense	Actual Costs Incurred			
2	**CAPITAL CORP.**	Corporate Aircraft		$41,938		$11,907
3						
4						
5						
6		Capital				
7		Corporate Aircraft	Actual Costs Incurred	2,161		
8						
9						
10						
11						
12						
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21						
22		Total Centennial Holding Capital Corporation Operating Revenues for the Year 2002			$ 67,760	
23						
24						
25						
26						
27						
28						
29	**TOTAL**	**Grand Total Affiliate Transactions**		$44,099	65.0812%	$11,907

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$23,975		
4		Advertising	Costs Incurred	21,098		
5		Air Service		73,713		
6		Automobile		2,264		
7		Bank Services		156,444		
8		Corporate Aircraft		38,734		
9		Consultant Fees		261,290		
10		Contract Services		417,043		
11		Directors Expenses		429,898		
12		Employee Benefits		75,068		
13		Employee Meeting		63,095		
14		Employee Reimbursable Expense		94,148		
15		Express Mail		136		
16		Insurance		477,847		
17		Legal Retainers & Fees		458,124		
18		Moving Allowance		551		
19		Meal Allowance		732		
20		Cash Donations		11,496		
21		Meal & Entertainment		50,877		
22		Industry Dues & Licenses		35,915		
23		Office Expenses		40,110		
24		Supplemental Insurance		772,744		
25		Permits & Filing Fees		4,324		
26		Postage		9,499		
27		Payroll		3,530,147		
28		Reference Materials		46,564		
29		Rental		201		
30		Seminars & Meeting Registrations		48,185		
31		Software Maintenance		35,590		
32		Training		35,667		
33		**Total MDU Resources Group, Inc.**		$7,215,479	0.8285%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department	* Various Corporate Overhead Allocation			
3		Automobile	Factors, Cost of Service Factors, Time	$13		
4		Air Service	Studies and /or Actual Costs Incurred	109		
5		Contract Services		12		
6		Employee Reimbursable Expense		230		
7		Freight		1		
8		Materials		766		
9		Office Expenses		258		
10		Office Telephone		68,157		
11		Organizational Dues		27		
12		Payroll		9,462		
13		Permits & Filing Fees		218		
14		Seminars & Meeting Registrations		102		
15						
16		Office Services	* General Office Complex and Office			
17		Automobile	Supplies Cost of Service Allocation	14		
18		Contract Services	Factors	1,118		
19		Employee Meetings		67		
20		Express Mail		12,490		
21		Rental of Office Equipment		523		
22		Office Expenses		3,517		
23		Postage		7,636		
24		Cost of Service - General Office Buildings		273,742		$63,403
25						
26		Information Systems	* Various Corporate Overhead Allocation			
27		Automobile	Factors and /or Actual Costs Incurred	27		
28		Air Service		155		
29		Contract Services		367		
30						
31						
32		Employee Reimbursable Expense		200		
33		Meals & Entertainment		76		
34		Office Expenses		12,573		

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	Professional Organ. Dues		8		
2		Payroll		13,371		
3		Reference Material		1		
4		Seminars & Meeting Registrations		678		
5		Software Maintenance		6		
6						
7		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
8		Automobile	Factors and /or Actual Costs Incurred	26		
9		Office Supplies		201		
10		Payroll		715		
11						
12						
13						
14		Other Direct Charges	Actual Costs Incurred			
15		Utility Discounts		40,054		4,585
16		Corporate/Commercial Air Service		29,110		
17		Computer/Software Support		357,073		
18		Electric Energy Usage Analysis		7,841		
19		Electric Consumption		18,239		0
20		Gas Consumption		50,162		47,193
21		Telephone		19,949		
22		Miscellaneous		114,912		
23						
24						
25		**Total Montana-Dakota Utilities Co.**		$ 1,044,206	0.1199%	$115,181

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	KNIFE RIVER CORPORATION	OTHER TRANSACTIONS/REIMBURSEMENTS				
2		True Up Charges Brazil/MDU Intl		$102,868		
3		Insurance		1,343,894		
4		Federal & State Tax Liability Payments		26,597,233		
5		KESOP carrying costs		482,381		
6		MGMT Incentive Comp Plan-Taxes		43,350		
7		Restricted Stock Program-Taxes		150,891		
8		Tax Deferred Savings Plan		124,230		
9		Interest		(34,077)		
10		Miscellaneous Reimbursements		13,817		
11						
12		**Total Other Transactions/Reimbursements**		$28,824,587	3.3098%	
13						
14		**Grand Total Affiliate Transactions**		$37,084,272	4.2582%	$115,181
15						
16						
17						
18		**Total Knife River Corporation Operating Expenses for 2002**			$870,882,028	

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$13,796		
4		Advertising	Costs Incurred	12,214		
5		Air Service		45,498		
6		Automobile		6,362		
7		Bank Services		90,028		
8		Corporate Aircraft		26,364		
9		Consultant Fees		189,840		
10		Contract Services		239,754		
11		Directors Expenses		237,254		
12		Employee Benefits		46,087		
13		Employee Meeting		36,308		
14		Employee Reimbursable Expense		65,510		
15		Express Mail		153		
16		Insurance		274,873		
17		Legal Retainers & Fees		262,453		
18		Meal Allowance		431		
19		Cash Donations		6,717		
20		Meal & Entertainment		38,279		
21		Moving Expense		317		
22		Industry Dues & Licenses		22,753		
23		Office Expenses		23,885		
24		Supplemental Insurance		444,650		
25		Permits & Filing Fees		2,627		
26		Postage		5,533		
27		Payroll		2,393,676		
28		Reference Materials		28,052		
29		Rental		2,058		
30		Seminars & Meeting Registrations		31,202		
31		Software Maintenance		20,486		
32		Training Material		20,525		
33		**Total MDU Resources Group, Inc.**		$4,587,685	2.4891%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department	* Various Corporate Overhead Allocation			
3		Expense	Factors, Cost of Service Factors, Time			
4		Automobile	Studies and /or Actual Costs Incurred	$745		
5		Air Service		42		
6		Annual Easements		1,630		
7		Contract Services		1,288		
8		Custodial Services		336		
9		Employee Reimbursable Expense		275		
10		Freight		13		
11		Materials		1,709		
12		Meals & Entertainment		154		
13		Office Expenses		149		
14		Office Telephone		31,954		
15		Payroll		11,372		
16		Permits & Filing Fees		283		
17		Photocopier		400		
18		Professional Organ Dues		22		
19		Reference Material		9		
20		Seminars & Meeting Registrations		32		
21		Utilities		3,176		
22						
23		Office Services	* General Office Complex and Office			
24		Expense	Supplies cost of Service Allocation			
25		Automobile	Factors	20		
26		Contract Services		1,741		
27		Employee Meetings		101		
28		Express Mail		7,181		
29						
30		Office Expenses		29,078		
31		Postage		4,436		
32		Cost of Service - General Office Buildings		349,657		$80,986
33						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	Purchasing Department	* Various Corporate Overhead Allocation			
2		Capital	Factors, Cost of Service Factors, Time			
3		Payroll	Studies and /or Actual Costs Incurred	13,948		
4		Office Expenses		115		
5						
6		Information Systems	* Various Corporate Overhead Allocation			
7		Expense	Factors and /or Actual Costs Incurred			
8		Automobile		20		
9		Air Service		67		
10		Contract Services		2,758		
11		Employee Reimbursable Expense		91		
12		Meals & Entertainment		29		
13		Office Expenses		80,167		
14		Payroll		4,988		
15		Professional Organ. Dues		12		
16		Reference Material		1		
17		Seminars & Meeting Registrations		274		
18		Software Maintenance		2		
19						
20		Region Operations	Actual Costs Incurred			
21		Expense				
22		Automobile		1,841		
23		Contract Services		265		
24		Company Work Equipment		59		
25		OfficeTelephone		69		
26		Payroll		4,809		
27		Utilities		154		

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	Transportation Department	* Various Corporate Overhead Allocation			
2		Capital	Factors, Time Studies and /or Actual			
3		Payroll	Costs incurred	11,506		
4		Clearing Accounts				
5		Automobile		1,543		
6		Air Service		132		
7		Contract Services		158		
8		Corporate Aircraft		74		
9		Custodial Services		313		
10		Employee Reimbursable Expense		137		
11		Materials		1,589		
12		Meals & Entertainment		115		
13		Office Expenses		16		
14		Office Telephone		256		
15		Professional Organ. Dues		3		
16		Payroll		4,913		
17		Utilities		417		
18						
19		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
20		Expense	Factors, Time Studies and /or Actual			
21		Automobile	Costs incurred	(145)		
22		Legal Fees		802		
23		Payroll		2,275		
24						
25						
26						
27						
28						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	Capital				
2		Automobile		55		
3		Air Service		573		
4		Professional Organ. Dues		6		
5		Employee Reimbursable Expense		247		
6		Meals & Entertainment		96		
7		Office Expenses		44		
8		Payroll		395		
9						
10		Other Direct Charges	Actual Costs Incurred			
11		Utility/Merchandise Discounts		113,372		65,823
12		Corporate Aircraft		70,304		
13		Contract Services		43,242		
14		Vehicle Maintenance		19,049		
15		Cathodic Protection		13,042		4,265
16		Purchased Power for Compressor Stations		86,155		73,029
17		Electric Compressor - Electricity Cost		332,015		146,718
18		Office Building Utilities		130,443		64,200
19		Computer Support		6,700		
20		Miscellaneous		117,175		
21		Pool Car Usage		5,102		
22						
23		Total Montana-Dakota Utilities Co. 1/		1,517,592	0.8234%	$435,020
24						
25		1/ Total Montana-Dakota Charges By Category				
26		Expense		1,480,941	0.8035%	
27		Capital		26,984	0.0146%	
28		Clearing		9,667	0.0052%	
29		Total		1,517,592	0.8233%	
30						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	WBI HOLDINGS, INC.	OTHER TRANSACTIONS/REIMBURSEMENTS				
2		Insurance	Actual Costs Incurred	$844,565		
3		Federal & State Tax Liability Payments		29,919,182		
4		Tax Deferred Savings Plan		29,337		
5		KESOP carrying costs		394,844		
6		MGMT Incentive Comp Plan-Taxes		43,464		
7		Restricted Stock Program-Taxes		36,951		
8		Interest		(19,603)		
9		Charges of Brazil Corp Development		56,677		
10		**Total Other Transactions/Reimbursements**		$31,305,418	16.9851%	
11						
12						
13		**Grand Total Affiliate Transactions**		$37,410,694	20.2975%	$435,020
14						
15						
16						
17		**Total WBI Holdings Operating Expenses for 2002**			$184,311,570	

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	UTILITY SERVICES, INC.	MDU RESOURCES GROUP, INC.				
2		Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$2,565		
4		Advertising	Costs Incurred	4,023		
5		Air Service		22,732		
6		Automobile		327		
7		Bank Services		16,739		
8		Corporate Aircraft		6,326		
9		Consultant Fees		22,098		
10		Contract Services		44,620		
11		Directors Expenses		44,103		
12		Employee Benefits		8,859		
13		Employee Meeting		6,748		
14		Employee Reimbursable Expense		21,940		
15		Express Mail		13		
16		Insurance		51,113		
17		Legal Retainers & Fees		48,485		
18		Moving Allowance		59		
19		Meal Allowance		78		
20		Cash Donations		1,229		
21		Meal & Entertainment		9,533		
22		Industry Dues & Licenses		4,022		
23		Office Expenses		4,351		
24		Supplemental Insurance		82,672		
25		Permits & Filing Fees		463		
26		Postage		1,019		
27		Payroll		435,070		
28		Reference Materials		4,919		
29		Rent		(5)		
30		Seminars & Meeting Registrations		5,704		
31		Software Maintenance		4,018		
32		Training Material		3,816		
33		**Total MDU Resources Group, Inc.**		$857,639	0.1929%	

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	UTILITY SERVICES, INC.	MONTANA-DAKOTA UTILITIES CO.				
2		Communications Department	* Various Corporate Overhead Allocation			
3		Air Service	Factors, Cost of Service Factors, Time	$4		
4		Professional Organ. Dues	Studies and /or Actual Costs Incurred	1		
5		Office Expenses		7		
6		Office Telephone		3,491		
7		Payroll		373		
8		Employee Reimbursable Expense		9		
9		Materials		34		
10		Permits & Filing Fees		23		
11		Seminars & Meeting Registrations		4		
12						
13		Office Services	* General Office Complex and Office			
14		Automobile	Supplies Cost of Service Allocation	1		
15		Contract Services	Factors	168		
16		Employee Meetings		11		
17		Express Mail		1,331		
18		Office Expenses		374		
19		Postage		814		
20		Cost of Service - General Office Buildings		246,037		$56,986
21						
22		Information Systems	* Various Corporate Overhead Allocation			
23		Contract Services	Factors and /or Actual Costs Incurred	38		
24		Employee Reimbursable Expense		13		
25		Office Expenses		1,456		
26		Payroll		1,884		
27		Air Services		10		
28		Seminars & Meeting Registrations		44		
29		Meal & Entertainment		4		

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	UTILITY SERVICES, INC.	USI President and COO	* Various Corporate Overhead Allocation			
2		Air Services	Factors, Time Studies and/or	14,130		
3		Corporate Aircraft	Actual Costs Incurred	17,255		
4		Meals and Entertainment		2,765		
5		Misc. Employee Benefits		465		
6		Office Supplies		559		
7		Other Reimbursable Exp		12,251		
8		Payroll		246,154		
9		Professional Organ. Dues		225		
10		Reference Material		164		
11						
12		Other Miscellaneous Departments	* Various Corporate Overhead Allocation			
13		Air Services	Factors, Time Studies and/or	1,086		
14		Employee Benefits	Actual Costs Incurred	159		
15		Office Supplies		22		
16		Payroll		157		
17		Office Expenses		661		
18						
19		Other Direct Charges	Actual Costs Incurred			
20		Legal Fees		185,035		
21		Contract Services		309,351		
22		Air Service		100,399		
23		Meals and Entertainment		6,834		
24		Employee Reimbursable Expense		22,531		
25		Telephone		320		
26		Consulting Service		31,080		
27		Permits and Filing Fees		7,632		
28		Northern Capital		42,224		
29		Software Implementation Project		704,882		
30		Gas Consumption		2,050		2,050
31		**Total Montana-Dakota Utilities Co.**		$1,964,522	0.4418%	$59,036

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	UTILITY SERVICES, INC.	OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
2		Federal & State Tax Liability Payments		$6,862,768		
3		Audit fees		84,000		
4		Insurance		489,253		
5		True Up Charges Brazil/MDU Intl		6,492		
6		Miscellaneous		132,068		
7		KESOP/Deferred Comp carrying costs		21,144		
8						
9		**Total Other Transactions/Reimbursements**		$7,595,724	1.7081%	
10						
11		**Grand Total Affiliate Transactions**		$10,417,885	2.3428%	$59,036
12						
13						
14						
15		**Total Utility Services, Inc. Operating Expenses for 2002**			$ 444,680,463	

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	MDU INTERNATIONAL	MDU RESOURCES GROUP, INC.				
2		Other Direct Charges	Actual Cost Incurred			
3		Legal Fees		$834,945		
4		Corporate/Commercial Airfare		209,241		
5		Employee Reimbursable Expense		50,733		
6		Consulting Service		475,044		
7		Permits and Filing Fees		330		
8		Payroll/Labor		203,307		
9						
10		**Total MDU Resources Group, Inc.**		$1,773,600		
11						
12		OTHER TRANSACTIONS/REIMBURSEMENTS				
13		Federal & State Tax Liability Payments		714,000		
14		Audit fees		80,456		
15		Miscellaneous		(100,796)		
16						
17		**Total Other Transactions/Reimbursements**		$693,660		
18						
19		**Grand Total Affiliate Transactions**		$2,467,260		
20						
21						

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL HOLDINGS	MDU RESOURCES GROUP, INC.				
2	CAPITAL CORP.	Corporate Overhead	* Various Corporate Overhead Allocation			
3		Audit Costs	Factors, Time Studies and/or Actual	$10		
4		Advertising	Costs Incurred	6		
5		Air Service		24		
6		Bank Services		77		
7		Corporate Aircraft		11		
8		Consultant Fees		52		
9		Contract Services		304		
10		Directors Expenses		14,157		
11		Employee Benefits		35		
12		Employee Meeting		13		
13		Employee Reimbursable Expense		16		
14		Legal Retainers & Fees		153		
15		Cash Donations		3		
16		Meal & Entertainment		9		
17		Industry Dues & Licenses		15		
18		Office Expenses		14		
19		Supplemental Insurance		293		
20		Permits & Filing Fees		9		
21		Postage		17		
22		Payroll		2,464		
23		Reference Materials		19		
24		Seminars & Meeting Registrations		(3)		
25		Software Maintenance		29		
26		Training		22		
27		**Total MDU Resources Group, Inc.**		$17,749	0.3522%	

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2002

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	CENTENNIAL HOLDINGS	Other Direct Charges	Actual costs incurred			
2	CAPITAL CORP.	Contract Services		$284,963		
3		Corporate/Commercial Air Service		64,840		
4		Computer/Software Costs		102,698		
5		Employee Reimbursable Expense		433,252		
6		Consulting Fees		156,493		
7		Permits & Filing Frees		9,849		
8		Electric Consumption		45,697		
9		Gas Consumption		13,197		
10		Rental		25,734		
11		Legal Fees		478,077		
12		Payroll		775,395		
13		Telephone		6,769		
14		Cost of Service-General Office Buildings		10,713		
15		**Total Other Direct Charges**		$2,407,677		
16						
17		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
18		Federal & State Tax Liability Payments		($313,000)		
19		Audit fees		30,000		
20		Insurance		207,375		
21		Miscellaneous		53,199		
22						
23						
24		**Total Other Transactions/Reimbursements**		($22,426)		
25						
26		**Grand Total Affiliate Transactions**		$2,403,000		
27						
28		**Total Centennial Holding Capital Corporation Operating Expenses for 2002**			$5,039,039	
29						

* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

MONTANA UTILITY INCOME STATEMENT

Year: 2002

	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	$64,354,421	$48,030,215	-25.37%
2				
3	Operating Expenses			
4	401 Operation Expenses	$57,848,757	$39,257,600	-32.14%
5	402 Maintenance Expense	767,611	748,622	-2.47%
6	403 Depreciation Expense	2,080,690	2,150,618	3.36%
7	404-405 Amort. & Depl. of Gas Plant	151,002	169,769	12.43%
8	406 Amort. of Gas Plant Acquisition Adjustments			
9	407.1 Amort. of Property Losses, Unrecovered Plant			
10	& Regulatory Study Costs			
11	407.2 Amort. of Conversion Expense			
12	408.1 Taxes Other Than Income Taxes	2,209,566	1,902,647	-13.89%
13	409.1 Income Taxes - Federal	1,928,616	(1,569,848)	-181.40%
14	- Other	461,924	(428,836)	-192.84%
15	410.1 Provision for Deferred Income Taxes	(1,755,496)	2,587,851	247.41%
16	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	(227,526)	344,692	251.50%
17	411.4 Investment Tax Credit Adjustments			
18	411.6 (Less) Gains from Disposition of Utility Plant			
19	411.7 Losses from Disposition of Utility Plant			
20	**TOTAL Utility Operating Expenses**	$63,465,144	$45,163,115	-28.84%
21	**NET UTILITY OPERATING INCOME**	$889,277	$2,867,100	222.41%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title	Last Year	This Year	% Change
1	Sales of Gas			
2	480 Residential	$42,258,645	$29,528,787	-30.12%
3	481 Commercial & Industrial - Small	25,206,559	16,855,419	-33.13%
4	Commercial & Industrial - Large	298	0	-100.00%
5	482 Other Sales to Public Authorities			
6	484 Interdepartmental Sales			
7	485 Intracompany Transfers			
8	Net Unbilled Revenue	(4,410,333)	415,235	109.42%
9	**TOTAL Sales to Ultimate Consumers**	63,055,169	46,799,441	-25.78%
10	483 Sales for Resale			
11	**TOTAL Sales of Gas**	$63,055,169	$46,799,441	-25.78%
12	Other Operating Revenues			
13	487 Forfeited Discounts & Late Payment Revenues			
14	488 Miscellaneous Service Revenues	$45,349	$38,551	-14.99%
15	489 Revenues from Transp. of Gas for Others 1/	1,105,062	1,024,563	-7.28%
16	490 Sales of Products Extracted from Natural Gas			
17	491 Revenues from Nat. Gas Processed by Others			
18	492 Incidental Gasoline & Oil Sales			
19	493 Rent From Gas Property	133,175	127,492	-4.27%
20	494 Interdepartmental Rents			
21	495 Other Gas Revenues	15,666	40,168	156.40%
22	**TOTAL Other Operating Revenues**	1,299,252	1,230,774	-5.27%
23	**Total Gas Operating Revenues**	$64,354,421	$48,030,215	-25.37%
24				
25	496 (Less) Provision for Rate Refunds			
26				
27	**TOTAL Oper. Revs. Net of Pro. for Refunds**	$64,354,421	$48,030,215	-25.37%

1/ Includes unbilled revenue.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2002

	Account Number & Title	Last Year	This Year	% Change
1	**Production Expenses**			
2	Production & Gathering - Operation			
3	750 Operation Supervision & Engineering			
4	751 Production Maps & Records			
5	752 Gas Wells Expenses			
6	753 Field Lines Expenses			
7	754 Field Compressor Station Expenses		NOT APPLICABLE	
8	755 Field Compressor Station Fuel & Power			
9	756 Field Measuring & Regulating Station Expense			
10	757 Purification Expenses			
11	758 Gas Well Royalties			
12	759 Other Expenses			
13	760 Rents			
14	**Total Operation - Natural Gas Production**			
15	Production & Gathering - Maintenance			
16	761 Maintenance Supervision & Engineering			
17	762 Maintenance of Structures & Improvements			
18	763 Maintenance of Producing Gas Wells			
19	764 Maintenance of Field Lines			
20	765 Maintenance of Field Compressor Sta. Equip.		NOT APPLICABLE	
21	766 Maintenance of Field Meas. & Reg. Sta. Equip.			
22	767 Maintenance of Purification Equipment			
23	768 Maintenance of Drilling & Cleaning Equip.			
24	769 Maintenance of Other Equipment			
25	**Total Maintenance- Natural Gas Prod.**			
26	**TOTAL Natural Gas Production & Gathering**			
27	Products Extraction - Operation			
28	770 Operation Supervision & Engineering			
29	771 Operation Labor			
30	772 Gas Shrinkage			
31	773 Fuel			
32	774 Power			
33	775 Materials			
34	776 Operation Supplies & Expenses		NOT APPLICABLE	
35	777 Gas Processed by Others			
36	778 Royalties on Products Extracted			
37	779 Marketing Expenses			
38	780 Products Purchased for Resale			
39	781 Variation in Products Inventory			
40	782 (Less) Extracted Products Used by Utility - Cr.			
41	783 Rents			
42	**Total Operation - Products Extraction**			
43	Products Extraction - Maintenance			
44	784 Maintenance Supervision & Engineering			
45	785 Maintenance of Structures & Improvements			
46	786 Maintenance of Extraction & Refining Equip.			
47	787 Maintenance of Pipe Lines		NOT APPLICABLE	
48	788 Maintenance of Extracted Prod. Storage Equip.			
49	789 Maintenance of Compressor Equipment			
50	790 Maintenance of Gas Meas. & Reg. Equip.			
51	791 Maintenance of Other Equipment			
52	**Total Maintenance - Products Extraction**			
53	**TOTAL Products Extraction**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2002

	Account Number & Title	Last Year	This Year	% Change
1	**Production Expenses - continued**			
2				
3	Exploration & Development - Operation			
4	795 Delay Rentals			
5	796 Nonproductive Well Drilling		NOT	
6	797 Abandoned Leases		APPLICABLE	
7	798 Other Exploration			
8	**TOTAL Exploration & Development**			
9				
10	Other Gas Supply Expenses - Operation			
11	800 Natural Gas Wellhead Purchases			
12	800.1 Nat. Gas Wellhead Purch., Intracomp. Trans.			
13	801 Natural Gas Field Line Purchases			
14	802 Natural Gas Gasoline Plant Outlet Purchases			
15	803 Natural Gas Transmission Line Purchases			
16	804 Natural Gas City Gate Purchases	$49,165,955	$34,269,291	-30.30%
17	805 Other Gas Purchases			
18	805.1 Purchased Gas Cost Adjustments	5,154,891	(7,086,673)	-237.47%
19	805.2 Incremental Gas Cost Adjustments			
20	806 Exchange Gas			
21	807.1 Well Expenses - Purchased Gas			
22	807.2 Operation of Purch. Gas Measuring Stations			
23	807.3 Maintenance of Purch. Gas Measuring Stations			
24	807.4 Purchased Gas Calculations Expenses			
25	807.5 Other Purchased Gas Expenses			
26	808.1 Gas Withdrawn from Storage -Dr.	8,926,986	7,953,021	-10.91%
27	808.2 (Less) Gas Delivered to Storage -Cr.	(14,149,207)	(4,356,543)	69.21%
28	809.2 (Less) Deliveries of Nat. Gas for Processing-Cr.			
29	810 (Less) Gas Used for Compressor Sta. Fuel-Cr.			
30	811 (Less) Gas Used for Products Extraction-Cr.			
31	812 (Less) Gas Used for Other Utility Operations-Cr.			
32	813 Other Gas Supply Expenses	138,697	116,158	-16.25%
33	**TOTAL Other Gas Supply Expenses**	$49,237,322	$30,895,254	-37.25%
34				
35	**TOTAL PRODUCTION EXPENSES**	$49,237,322	$30,895,254	-37.25%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2002

	Account Number & Title		Last Year	This Year	% Change
1	**Storage, Terminaling & Processing Expenses**				
2					
3	Underground Storage Expenses - Operation				
4	814	Operation Supervision & Engineering			
5	815	Maps & Records			
6	816	Wells Expenses			
7	817	Lines Expenses			
8	818	Compressor Station Expenses			
9	819	Compressor Station Fuel & Power		NOT	
10	820	Measuring & Reg. Station Expenses		APPLICABLE	
11	821	Purification Expenses			
12	822	Exploration & Development			
13	823	Gas Losses			
14	824	Other Expenses			
15	825	Storage Well Royalties			
16	826	Rents			
17		**Total Operation - Underground Strg. Exp.**			
18					
19	Underground Storage Expenses - Maintenance				
20	830	Maintenance Supervision & Engineering			
21	831	Maintenance of Structures & Improvements			
22	832	Maintenance of Reservoirs & Wells			
23	833	Maintenance of Lines			
24	834	Maintenance of Compressor Station Equip.		NOT	
25	835	Maintenance of Meas. & Reg. Sta. Equip.		APPLICABLE	
26	836	Maintenance of Purification Equipment			
27	837	Maintenance of Other Equipment			
28		**Total Maintenance - Underground Storage**			
29		**TOTAL Underground Storage Expenses**			
30					
31	Other Storage Expenses - Operation				
32	840	Operation Supervision & Engineering			
33	841	Operation Labor and Expenses			
34	842	Rents		NOT	
35	842.1	Fuel		APPLICABLE	
36	842.2	Power			
37	842.3	Gas Losses			
38		**Total Operation - Other Storage Expenses**			
39					
40	Other Storage Expenses - Maintenance				
41	843.1	Maintenance Supervision & Engineering			
42	843.2	Maintenance of Structures & Improvements			
43	843.3	Maintenance of Gas Holders			
44	843.4	Maintenance of Purification Equipment		NOT	
45	843.6	Maintenance of Vaporizing Equipment		APPLICABLE	
46	843.7	Maintenance of Compressor Equipment			
47	843.8	Maintenance of Measuring & Reg. Equipment			
48	843.9	Maintenance of Other Equipment			
49		**Total Maintenance - Other Storage Exp.**			
50		**TOTAL - Other Storage Expenses**			
51					
52	**TOTAL - STORAGE, TERMINALING & PROC.**				

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2002

	Account Number & Title	Last Year	This Year	% Change
1	**Transmission Expenses**			
2	Operation			
3	850 Operation Supervision & Engineering			
4	851 System Control & Load Dispatching			
5	852 Communications System Expenses			
6	853 Compressor Station Labor & Expenses			
7	854 Gas for Compressor Station Fuel		NOT	
8	855 Other Fuel & Power for Compressor Stations		APPLICABLE	
9	856 Mains Expenses			
10	857 Measuring & Regulating Station Expenses			
11	858 Transmission & Compression of Gas by Others			
12	859 Other Expenses			
13	860 Rents			
14	**Total Operation - Transmission**			
15	Maintenance			
16	861 Maintenance Supervision & Engineering			
17	862 Maintenance of Structures & Improvements			
18	863 Maintenance of Mains			
19	864 Maintenance of Compressor Station Equip.		NOT	
20	865 Maintenance of Measuring & Reg. Sta. Equip.		APPLICABLE	
21	866 Maintenance of Communication Equipment			
22	867 Maintenance of Other Equipment			
23	**Total Maintenance - Transmission**			
24	**TOTAL Transmission Expenses**			
25	**Distribution Expenses**			
26	Operation			
27	870 Operation Supervision & Engineering	$350,898	$310,037	-11.64%
28	871 Distribution Load Dispatching	50,922	49,689	-2.42%
29	872 Compressor Station Labor and Expenses			
30	873 Compressor Station Fuel and Power			
31	874 Mains and Services Expenses	652,780	670,107	2.65%
32	875 Measuring & Reg. Station Exp.-General	26,987	14,318	-46.94%
33	876 Measuring & Reg. Station Exp.-Industrial	15,541	4,627	-70.23%
34	877 Meas. & Reg. Station Exp.-City Gate Ck. Sta.			
35	878 Meter & House Regulator Expenses	411,161	402,364	-2.14%
36	879 Customer Installations Expenses	775,730	762,373	-1.72%
37	880 Other Expenses	844,025	894,165	5.94%
38	881 Rents	21,722	18,007	-17.10%
39	**Total Operation - Distribution**	$3,149,766	$3,125,687	-0.76%
40	Maintenance			
41	885 Maintenance Supervision & Engineering	$137,990	$128,763	-6.69%
42	886 Maintenance of Structures & Improvements	1,492	1,077	-27.82%
43	887 Maintenance of Mains	84,303	85,295	1.18%
44	888 Maint. of Compressor Station Equipment			
45	889 Maint. of Meas. & Reg. Station Exp.-General	14,443	6,614	-54.21%
46	890 Maint. of Meas. & Reg. Sta. Exp.-Industrial	2,684	3,247	20.98%
47	891 Maint. of Meas. & Reg. Sta. Equip.-City Gate			
48	892 Maintenance of Services	115,995	96,785	-16.56%
49	893 Maintenance of Meters & House Regulators	57,633	56,290	-2.33%
50	894 Maintenance of Other Equipment	172,442	168,046	-2.55%
51	**Total Maintenance - Distribution**	$586,982	$546,117	-6.96%
52	**TOTAL Distribution Expenses**	$3,736,748	$3,671,804	-1.74%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2002

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Customer Accounts Expenses**			
3	Operation			
4	901 Supervision	$137,449	$134,984	-1.79%
5	902 Meter Reading Expenses	484,793	455,640	-6.01%
6	903 Customer Records & Collection Expenses	1,194,825	1,158,643	-3.03%
7	904 Uncollectible Accounts Expenses	409,285	43,209	-89.44%
8	905 Miscellaneous Customer Accounts Expenses	120,766	105,594	-12.56%
9				
10	**TOTAL Customer Accounts Expenses**	$2,347,118	$1,898,070	-19.13%
11				
12	**Customer Service & Informational Expenses**			
13	Operation			
14	907 Supervision	$4,392	$4,302	-2.05%
15	908 Customer Assistance Expenses	26,763	23,577	-11.90%
16	909 Informational & Instructional Advertising Exp.	30,000	21,397	-28.68%
17	910 Miscellaneous Customer Service & Info. Exp.	437	252	-42.33%
18				
19	**TOTAL Customer Service & Info. Expenses**	$61,592	$49,528	-19.59%
20				
21	**Sales Expenses**			
22	Operation			
23	911 Supervision	$103,745	$94,223	-9.18%
24	912 Demonstrating & Selling Expenses	217,392	209,214	-3.76%
25	913 Advertising Expenses	28,772	16,717	-41.90%
26	916 Miscellaneous Sales Expenses	19,465	16,371	-15.90%
27				
28	**TOTAL Sales Expenses**	$369,374	$336,525	-8.89%
29				
30	**Administrative & General Expenses**			
31	Operation			
32	920 Administrative & General Salaries	$900,301	$953,917	5.96%
33	921 Office Supplies & Expenses	512,849	537,763	4.86%
34	922 (Less) Administrative Expenses Transferred - Cr.			
35	923 Outside Services Employed	147,748	161,130	9.06%
36	924 Property Insurance	37,968	65,207	71.74%
37	925 Injuries & Damages	180,674	246,189	36.26%
38	926 Employee Pensions & Benefits	725,920	851,084	17.24%
39	927 Franchise Requirements			
40	928 Regulatory Commission Expenses	1,193	420	-64.79%
41	929 (Less) Duplicate Charges - Cr.			
42	930.1 General Advertising Expenses	27,600	19,374	-29.80%
43	930.2 Miscellaneous General Expenses	127,614	68,793	-46.09%
44	931 Rents	21,718	48,659	124.05%
45				
46	**TOTAL Operation - Admin. & General**	$2,683,585	$2,952,536	10.02%
47	Maintenance			
48	935 Maintenance of General Plant	$180,629	$202,505	12.11%
49				
50	**TOTAL Administrative & General Expenses**	$2,864,214	$3,155,041	10.15%
51	**TOTAL OPERATION & MAINTENANCE EXP.**	$58,616,368	$40,006,222	-31.75%

MONTANA TAXES OTHER THAN INCOME

Year: 2002

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	$418,998	$415,905	-0.74%
2	Secretary of State	152	265	74.34%
3	Highway Use Tax	131	115	-12.21%
4	Montana Consumer Counsel	54,724	37,867	-30.80%
5	Montana PSC	186,032	108,867	-41.48%
6	Franchise Taxes	15,061	16,260	7.96%
7	Property Taxes	1,528,768	1,318,975	-13.72%
8	Tribal Taxes	5,700	4,393	-22.93%
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50	**TOTAL MT Taxes other than Income**	$2,209,566	$1,902,647	-13.89%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2002

Name of Recipient	Nature of Service	Total Company	Montana	% Montana
Aerial Contractors, Inc	Contract Services	$406,556	-	0.00%
API Construction Company	Construction Services	118,280	-	0.00%
Barr Engineering Company	Contract Services	219,042	-	0.00%
Bison Engineering, Inc	Construction Services	174,676	-	0.00%
Bullinger Tree Service	Tree Trimming Service	194,346	41	0.02%
Cameo Rose Construction, Inc	Construction Services	155,658	-	0.00%
Carey Y Cia LTDA	Consulting and Legal - Due Diligence	111,919	-	0.00%
Chief Construction	Construction Services	437,489	-	0.00%
Christensen & Associates	Consultant - Investor Relations	108,043	3,388	3.14%
Cynthia J Skibinski	Consultant - CIS System	197,190	22,073	11.19%
Deloitte & Touche, LLP	Auditing and Consulting Services	275,080	10,835	3.94%
Diversified Graphic, Inc	Annual Report	158,812	4,981	3.14%
Duffield Construction, Inc	Construction Services	159,859	-	0.00%
Edling Electric, Inc	Construction Services-Electrical	153,846	-	0.00%
Energy & Environmental Research	Consulting Services	94,157	-	0.00%
Ernst & Young, LLP	Legal Services	167,826	-	0.00%
Fischer Contracting	Contract Services	79,034	-	0.00%
GE Power Services	Construction Services	2,227,990	-	0.00%
GE-Harris	Construction Services	220,185	-	0.00%
General Electric Company	Contract Services	398,081	-	0.00%
Gustafson Builders	Construction Services	348,301		0.00%
H. Zinder & Associates	Consulting Services	281,457	35,612	12.65%
Hamilton Spray	Contract Services - Pole Treatment	224,105		0.00%
Hay Group, Inc	Consulting Services	76,405	11,270	14.75%
Hedahls of Bismarck, Inc	Contract Services - Auto and Work Equip.	165,674	369	0.22%
Horsley Specialties, Inc	Contract Services	109,000		0.00%
Hughes, Kellner, Sullivan	Legal Services	100,920	33,963	33.65%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2002

Name of Recipient	Nature of Service	Total Company	Montana	% Montana
IBM	Contract Services - Computer Maintenance	$186,215	$20,731	11.13%
Image Printing, Inc	Printing Services	75,396	2,361	3.13%
Industrial Contractors, Inc	Construction Services	571,071		0.00%
Intermountain Tree Expert Co.	Tree Trimming Service	114,594		0.00%
James W. Sewall Company	Consulting Services	394,977	49,484	12.53%
Kappel Tree Service	Tree Trimming Service	78,548		0.00%
McDermott, Will & Emery	Legal Services	89,946	2,229	2.48%
MCM General Contractors, Inc	Construction Services	104,931		0.00%
Moody's Investors Services	Financial Services	107,800	6,648	6.17%
Navigant Consulting, Inc	Consulting Services	148,359	51,731	34.87%
New York Life	K-Plan Administrator	231,650		0.00%
Northern Improvement Co.	Contract Services	101,202		0.00%
Norwest Mine Services, Inc	Consulting Services	329,789		0.00%
One Call Locators, LTD	Line Location Service	776,771	183,642	23.64%
Osmose Wood	Contract Services - Pole Treatment	106,969		0.00%
Pearce & Durick	Legal Services	113,589	33	0.03%
Pitman Drilling Inc	Construction Services	98,608	-	0.00%
Pole Maintenance Company	Contract Services - Pole Treatment	164,331	-	0.00%
Power Generation Service	Contract Services	353,008	-	0.00%
Progressive Maintenance Co.	Custodial Services	76,718	7,776	10.14%
RealFoundations, Inc	Contract Services-Software Development	381,410	-	0.00%
Rocky Mountain Line	Construction Services	303,707	132,008	43.47%
Rolta International, Inc	Contract Services	187,829	23,532	12.53%
Sargent & Lundy, LLC	Consulting Services	244,052	-	0.00%
Skeels Electric Company	Contract Services - Electrical	71,009	7,807	10.99%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2002

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Southern Cross Corporation	Contract Services - Leak Detection	$222,745	$57,384	25.76%
2					
3	Standard & Poor's	Financial Services	90,299	3,230	3.58%
4					
5	State-Line Contractors, Inc	Construction Services	133,951	119,165	88.96%
6					
7	Tetra Tech Em, Inc	Consulting Services	159,947	-	0.00%
8					
9	The Industrial Company Wyoming	Contract Services - Turbines	284,210	-	0.00%
10					
11	Thelen Reid & Priest, LLP	Legal Services	2,631,653	26,521	1.01%
12					
13	Towers Perrin	Consultant - Compensation and Benefits	517,056	33,189	6.42%
14					
15	Trusecure Corporation	Information System Security	159,315	4,996	3.14%
16					
17	Underground Locators, LLC	Line Location Service	109,698	2,494	2.27%
18					
19	US Bank	Bank Services	194,231	33,146	17.07%
20					
21	Utility Partners, LC	Consultant - Mobile Service Computer	114,448	16,300	14.24%
22					
23	Veirano & Advogados Associates	Legal Services	77,645	-	0.00%
24					
25	Wells Fargo	Stock Transfer Agent and ESOP Admin	337,760	10,521	3.11%
26					
27	Williston Basin	Contract Services	77,066	15,161	19.67%
28					
29	**TOTAL Payments for Services**		17,886,431	932,623	5.21%

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2002

	Description	Total Company	Montana	% Montana
1	Contributions to Candidates by PAC	$14,425	$3,800	26.34%
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43	**TOTAL Contributions**	$14,425	$3,800	26.34%

Pension Costs

Year: 2002

	Item	Current Year	Last Year	% Change
1	Plan Name MDU Resources Group, Inc. Master Pension Plan Trust			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	PROPRIETARY SCHEDULE			
4	PROPRIETARY SCHEDULE			
5				
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year			
8	Service cost			
9	Interest Cost			
10	Plan participants' contributions			
11	Amendments	PROPRIETARY SCHEDULE		
12	Actuarial (Gain) Loss			
13	Acquisition			
14	Benefits paid			
15	Benefit obligation at end of year			
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year			
18	Actual return on plan assets			
19	Acquisition	PROPRIETARY SCHEDULE		
20	Employer contribution			
21	Plan participants' contributions			
22	Benefits paid			
23	Fair value of plan assets at end of year			
24	**Funded Status**			
25	Unrecognized net actuarial loss			
26	Unrecognized prior service cost	PROPRIETARY SCHEDULE		
27	Unrecognized net transition obligation			
28	Accrued benefit cost			
29				
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	6.75	7.25	-6.90%
32	Expected return on plan assets	8.50	8.50	0.00%
33	Rate of compensation increase	4.50	5.00	-10.00%
34				
35	**Components of Net Periodic Benefit Costs**			
36	Service cost			
37	Interest cost			
38	Expected return on plan assets	PROPRIETARY SCHEDULE		
39	Amortization of prior service cost			
40	Recognized net actuarial gain			
41	Transition amount amortization			
42	Net periodic benefit cost			
43				
44	**Montana Intrastate Costs:**			
45	Pension Costs	PROPRIETARY SCHEDULE		
46	Pension Costs Capitalized			
47	Accumulated Pension Asset (Liability) at Year End			
48	**Number of Company Employees:**			
49	Covered by the Plan			
50	Not Covered by the Plan	PROPRIETARY SCHEDULE		
51	Active			
52	Retired			
53	Deferred Vested Terminated			

Other Post Employment Benefits (OPEBS)

	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number:			
4	Order numbers:			
5	Amount recovered through rates -			
6	**Weighted-average Assumptions as of Year End**			
7	Discount rate	6.75	7.25	-6.90%
8	Expected return on plan assets	7.50	7.50	0.00%
9	Medical Cost Inflation Rate	PROPRIETARY SCHEDULE		
10	Actuarial Cost Method	PROPRIETARY SCHEDULE		
11	Rate of compensation increase	4.50	5.00	-10.00%
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**VEBA**			
14	**Describe any Changes to the Benefit Plan:**			
15				
16				
	TOTAL COMPANY			
17	**Change in Benefit Obligation**			
18	Benefit obligation at beginning of year			
19	Service cost			
20	Interest Cost			
21	Plan participants' contributions			
22	Amendments	PROPRIETARY SCHEDULE		
23	Actuarial (Gain) Loss			
24	Acquisition			
25	Benefits paid			
26	Benefit obligation at end of year			
27	**Change in Plan Assets**			
28	Fair value of plan assets at beginning of year			
29	Actual return on plan assets			
30	Acquisition	PROPRIETARY SCHEDULE		
31	Employer contribution			
32	Plan participants' contributions			
33	Benefits paid			
34	Fair value of plan assets at end of year			
35	**Funded Status**			
36	Unrecognized net actuarial loss			
37	Unrecognized prior service cost	PROPRIETARY SCHEDULE		
38	Unrecognized transition obligation			
39	Accrued benefit cost			
40	**Components of Net Periodic Benefit Costs**			
41	Service cost			
42	Interest cost			
43	Expected return on plan assets	PROPRIETARY SCHEDULE		
44	Amortization of prior service cost			
45	Recognized net acturial gain			
46	Transition amount amortization			
47	Net periodic benefit cost			
48	**Accumulated Post Retirement Benefit Obligation**			
49	Amount Funded through VEBA			
50	Amount Funded through 401(h)	PROPRIETARY SCHEDULE		
51	Amount Funded through Other ________________			
52	TOTAL			
53	Amount that was tax deductible - VEBA			
54	Amount that was tax deductible - 401(h)			
55	Amount that was tax deductible - Other __________			
56	TOTAL			

1/ Estimated.

Other Post Employment Benefits (OPEBS) Continued

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan			
3	Not Covered by the Plan			
4	Active		PROPRIETARY SCHEDULE	
5	Retired			
6	Spouses/Dependants covered by the Plan			
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost		NOT APPLICABLE	
11	Interest Cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial Gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition			
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss			
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost			
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount Funded through VEBA			
39	Amount Funded through 401(h)			
40	Amount Funded through other ______________			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension Costs			
48	Pension Costs Capitalized			
49	Accumulated Pension Asset (Liability) at Year End			
50	**Number of Montana Employees:**			
51	Covered by the Plan			
52	Not Covered by the Plan			
53	Active			
54	Retired			
55	Spouses/Dependants covered by the Plan			

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 16

Year: 2002

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1							
2							
3							
4							
5			PROPRIETARY SCHEDULE				
6							
7							
8							
9							
10							

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 17

Year: 2002

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

Line No.	Name/Title	Base Salary	Bonuses	Other 1/	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Martin A. White - Chairman of the Board, President & C.E.O.	$517,038	$509,340	$6,000	$1,032,378	$1,604,400	-36%
2	Douglas C. Kane - Executive Vice President Chief Administrative & Corporate Development Officer 2/	273,942		1,069,333	1,343,275	610,773	120%
3	Ronald D. Tipton - C.E.O. of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co.	306,815	111,958	6,000	424,773	540,275	-21%
4	Warren L. Robinson - Executive Vice President, Treasurer & Chief Financial Officer	278,265	182,840	6,000	467,105	599,567	-22%
5	Lester H. Loble, II - Vice President, General Counsel & Secretary	236,688	153,455	7,860	398,003	488,016	-18%
6	Vern A. Raile - Senior Vice President, Controller & Chief Accounting Officer	169,037	88,808	6,166	264,011	283,370	-7%

1/ See page 20a for details.
2/ Mr. Kane resigned as an officer of the Company on October 31, 2002.

EXECUTIVE COMPENSATION

SUMMARY COMPENSATION TABLE

(a)	Annual compensation				Long-term compensation			
					Awards		Payouts	
Name and principal position	(b) Year	(c) Salary ($)	(d) Bonus(1) ($)	(e) Other annual compensation(2) ($)	(f) Restricted stock awards ($)	(g) Securities underlying Options/SARs (#)	(h) LTIP payouts ($)	(i) All other compensation(7) ($)
Martin A. White —Chairman of the Board, President & C.E.O.	2002	517,038	509,340		—(3)	—	—	6,000
	2001	450,000	374,500		594,800(4)	180,000(5)	—	5,100
	2000	394,269	333,239		198,125(4)	—	393,118(6)	5,100
Douglas C. Kane —Executive Vice President, Chief Administrative & Corporate Development Officer(8)	2002	273,942	—		—(3)	—	—	1,069,333
	2001	249,127	145,446		148,700(4)	62,400(5)	—	5,100
	2000	226,654	140,035		99,063(4)	—	178,690(6)	5,100
Ronald D. Tipton —C.E.O. of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co.	2002	306,815	111,958		—(3)	—	—	6,000
	2001	279,038	35,437		148,700(4)	72,000(5)	—	5,100
	2000	254,277	135,024		99,063(4)	—	181,517(6)	5,100
Warren L. Robinson —Executive Vice President, Treasurer & Chief Financial Officer	2002	278,265	182,840		—(3)	—	—	6,000
	2001	237,077	146,290		148,700(4)	62,400(5)	—	5,100
	2000	188,462	110,912		79,250(4)	—	121,529(6)	5,100
Lester H. Loble, II —Executive Vice President, General Counsel & Secretary	2002	236,688	153,455	1,860	—(3)	—	—	6,000
	2001	190,846	105,219	13,291	118,960(4)	54,600(5)	—	5,100
	2000	161,654	81,486	4,551	59,438(4)	—	89,345(6)	4,850
Vernon A. Raile —Senior Vice President, Controller and Chief Accounting Officer	2002	169,037	88,808	1,095	—(3)	—	—	5,071
	2001	146,394	58,122	10,194	44,610(4)	20,800(5)	—	3,250
	2000	124,644	52,815	2,591	49,531(4)	—	50,052(6)	3,739

(1) Granted pursuant to the Executive Incentive Compensation Plan.

(2) Above-market interest on deferred compensation.

(3) At December 31, 2002, the Named Officers held the following amounts of restricted stock: Mr. White—35,000 shares ($903,350); Mr. Kane—0 shares; Mr. Tipton—12,500 shares ($322,625); Mr. Robinson—11,000 shares ($283,910); Mr. Loble—8,500 shares ($219,385) and Mr. Raile—5,250 shares ($135,503).

(4) Valued at fair market value on the date of grant. Nonpreferential dividends are paid on the restricted stock.

(5) Options granted pursuant to the 1992 KESOP or the 1997 Executive Long-Term Incentive Plan for the 2001-2003 performance cycle.

(6) Dividend equivalents paid with respect to options granted pursuant to the 1992 KESOP for the 1998-2000 performance cycle.

(7) Totals shown are the Company contributions to the Company 401(k) Retirement Plan except for Mr. Kane. Mr. Kane's total is comprised of $6,000 Company contribution to the Company 401(k) Retirement Plan and $1,063,333 paid in connection with his resignation as an officer on October 31, 2002.

(8) Mr. Kane resigned as an officer of the Company on October 31, 2002.

AGGREGATED OPTION/SAR EXERCISES IN LAST FISCAL YEAR AND FISCAL YEAR-END OPTION/SAR VALUES

(a) Name	(b) Shares acquired on exercise (#)	(c) Value realized ($)	(d) Number of securities underlying unexercised options at fiscal year-end(1) (#)		(e) Value of unexercised, in-the-money options at fiscal year-end ($)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Martin A. White	—	—	60,760	180,000	274,635	
Douglas C. Kane	—	—	55,800	0	252,216	
Ronald D. Tipton	—	—	49,125	72,000	222,045	
Warren L. Robinson	—	—	37,950	62,400	171,534	
Lester H. Loble, II	—	—	34,000	54,600	207,309	
Vernon A. Raile	—	—	15,630	20,800	70,648	

(1) Vesting is accelerated upon a change in control.

PENSION PLAN TABLE

Remuneration	Years of Service 15	20	25	30	35
$125,000	$ 79,229	$ 87,759	$ 96,288	$104,818	$113,347
150,000	95,346	105,689	116,031	126,373	136,715
175,000	111,464	123,619	135,773	147,928	160,082
200,000	129,501	143,469	157,436	171,403	185,370
225,000	140,481	154,449	168,416	182,383	196,350
250,000	151,401	165,369	179,336	193,303	207,270
300,000	187,641	201,609	215,576	229,543	243,510
350,000	235,221	249,189	263,156	277,123	291,090
400,000	276,201	290,169	304,136	318,103	332,070
450,000	316,101	330,069	344,036	358,003	371,970
500,000	387,501	401,469	415,436	429,403	443,370
550,000	387,501	401,469	415,436	429,403	443,370

The Table covers the amounts payable under the Salaried Pension Plan and non-qualified Supplemental Income Security Plan (SISP).

Pension benefits are determined by the step-rate formula that places emphasis on the highest consecutive 60 months of earnings within the final 10 years of service.

Benefits for single participants under the Salaried Pension Plan are paid as straight life amounts and benefits for married participants are paid as actuarially reduced pensions with a survivorship benefit for spouses, unless participants choose otherwise.

The Salaried Pension Plan also permits pre-retirement survivorship benefits upon satisfaction of certain conditions. Additionally, certain reductions are made for employees electing early retirement.

The Internal Revenue Code places maximum limitations on benefit amounts that may be paid under the Salaried Pension Plan.

The Company has adopted a non-qualified SISP for senior management personnel. In 2002, 92 senior management personnel participated in the SISP, including the Named Officers.

Both plans cover salary shown in column (c) of the Summary Compensation Table and exclude bonuses and other forms of compensation.

Upon retirement and reaching age 65, participants in the SISP may elect a retirement benefit or a survivors' benefit with the benefits payable monthly for 15 years or as an equivalent life annuity.

As of December 31, 2002, the Named Officers were credited with the following years of service under the plans:

Name	Pension Service Years	SISP Service Years
Martin A. White	11	11
Douglas C. Kane	31	21
Ronald D. Tipton	19	19
Warren L. Robinson	14	14
Lester H. Loble, II	15	15
Vernon A. Raile	22	21

The maximum years of service for benefits under the Pension Plan is 35. Vesting under the SISP begins at 3 years and is complete after 10 years. Benefit amounts under both plans are not subject to reduction for offset amounts.

CHANGE-OF-CONTROL AND SEVERANCE ARRANGEMENTS

The Company entered into Change of Control Employment Agreements with the Named Officers and other executives ("executives") in November 1998, which provide certain protections to the executives in the event there is a change of control of the Company.

If a change of control occurs, the agreements provide for a three-year employment period from the date of the change of control, during which the executive is entitled to receive a base salary not less than the highest amount paid within the preceding twelve months, and annual bonuses not less than the highest bonus paid within the three years before the change of control, and to participate in the Company's incentive, savings, retirement and welfare benefit plans.

The agreements also provide that specified severance payments and benefits would be provided if the executive's employment is terminated during the employment period (or if connected to the change of control, prior thereto) by the Company, other than for cause or disability, or by the executive for good reason, which includes for any reason during the 30-day period beginning on the first anniversary of the change of control.

In such event, the executive would receive an amount equal to three times his annual base pay plus three times his highest annual bonus (as defined). In addition, he would receive (i) an immediate pro-rated cash-out of his bonus for the year of termination based on the highest annual bonus and (ii) an amount equal to the excess of (a) the actuarial equivalent of the benefit under Company qualified and nonqualified retirement plans that he would receive if he continued employment with the Company for an additional three years over (b) the actual benefit paid or payable under these plans.

The executive and family would continue to be covered by the Company's welfare benefit plans for three years. The executive also would receive outplacement benefits. Finally, the executive would receive an additional payment if necessary to make him or her whole for any federal excise tax on excess parachute payments imposed upon the executive, unless the total parachute payments were not more than 110% of the safe harbor amount for that tax (in which event the executive's payments would be reduced to the safe harbor amount).

For these purposes, "cause" generally means the executive's willful and continued failure to substantially perform his duties or willfully engaging in illegal conduct or misconduct materially injurious to the Company. "Good reason" generally includes the diminution of the executive's position, authority, duties or responsibilities, the reduction of the executive's pay or benefits, and relocation or increased travel obligations.

Subject to certain exceptions described in the agreements, a "change of control" is defined in general as (i) the acquisition by an individual, entity, or group of 20% or more of the Company's voting securities; (ii) a turnover in a majority of the Board of Directors without the approval of a majority of the members of the Board who were members of the Board as of November 1998 or whose election was approved by such Board members; (iii) a merger or similar transaction; or (iv) the stockholders' approval of the Company's liquidation or dissolution.

The Company entered into a separation and release agreement with Mr. Douglas C. Kane in October 2002. Under the agreement, Mr. Kane agreed to resign, effective October 31, 2002, from his positions as Executive Vice President and Chief Administrative and Corporate Development Officer, and from his membership on the boards of directors of the Company and any related entities, and to become Special Projects Advisor to the Chief Executive Officer from November 1, 2002 until May 31, 2004. As Special Projects Advisor, Mr. Kane will receive a monthly salary of approximately $23,000 until May 31, 2004. In addition, as consideration for Mr. Kane's agreement to release all claims related to his employment and membership on the Company's boards or termination thereof, including any rights to future participation in various stock and bonus plans, Mr. Kane received $1,063,333 in January 2003. Mr. Kane forfeited his unvested stock options. Termination of employment for purposes of his vested stock options will be May 31, 2004. Mr. Kane's change of control agreement has expired and he acknowledged that he has no rights under that agreement. Other benefits to which Mr. Kane is entitled or to which he will become entitled upon termination of his position as Special Projects Advisor are determined in accordance with the terms and conditions of the Company's plans and programs.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

Introduction

The Compensation Committee of the Board of Directors is responsible for determining the compensation of the Company's executive officers. Composed entirely of non-employee Directors, the Committee meets several times each year to review and determine compensation for the executive officers, including the Chief Executive Officer.

Executive Compensation

During 2002, the Compensation Committee conducted a study of the Company's executive compensation programs. With assistance from outside advisors, the Committee evaluated key elements of total direct compensation in the current program, including base salary, annual incentives and long-term incentives. The evaluation process included current trends in competitive compensation and legal and regulatory developments. The outside advisors also surveyed employees, including management, and Directors for their insight into the effectiveness of the current compensation program and desired outcomes of a new program. Based upon this, beginning in 2003, the Committee has made several changes to its approach to long-term incentive compensation, including the elimination of stock options and restricted stock grants. The changes are discussed below.

The Committee believes that appropriate compensation levels succeed in both attracting and motivating high quality employees. To implement this philosophy, the Committee analyzes trends in compensation among comparable companies participating in the oil and gas industry, segments of the energy and mining industries, the peer group of companies used in the graph following this report, and similar companies from general industry. The Committee then sets compensation levels that it believes are competitive within the industry and structured in a manner that rewards successful job performance. There are three components of total executive compensation: base salary, annual incentive compensation, and long-term incentive compensation.

In setting base salaries, the Committee does not use a particular formula. In addition to the above data, other factors the Committee uses in its analysis include the executive's current salary in comparison to the competitive industry standard as well as individual performance. Mr. White, the Chairman, President and Chief Executive Officer, received a 15.6% increase in base salary for 2002. During 2002, only approximately 27.8% of Mr. White's compensation was base pay. The remainder was performance-based. This reflects the Committee's belief in the importance of having substantial at risk compensation to provide a direct and strong link between performance and executive pay. For the other Named Officers, the Committee targeted salaries at the midpoint of the competitive industry standard, rather than at 95% of the midpoint, as in the past. The other Named Officers received base salary increases averaging 15.38% for 2002.

In keeping with the Committee's belief that compensation should be directly linked to successful performance, the Company employs both annual and long-term incentive compensation plans. The annual incentive compensation is determined under the Executive Incentive Compensation Plan. The Committee makes awards based upon the level of corporate earnings, cost efficiency, and individual performance. Mr. White received a total of $509,340 (or 130.6% of the targeted amount) in annual incentive compensation for 2002; the other Named Officers received an average of $141,701 or 130.6% of the targeted amount, (except Mr. Tipton who received $111,958 or 72.7% of the targeted amount and Mr. Kane who did not receive a bonus), based upon achievement of corporate earnings and individual performance above the target level.

Long-term incentive compensation serves to encourage successful strategic management and is awarded under two plans: the 1992 Key Employee Stock Option Plan and the 1997 Executive Long-Term Incentive Plan. No options were granted in 2002. Options that were granted in 2001 with a three-year performance cycle (2001-2003) remain outstanding.

The Committee accelerated vesting of 54 percent of the restricted stock granted under the 1997 Executive Long-Term Incentive Plan, based on achievement of performance goals for the three-year period 2000-2002 at the 54th percentile.

In recent years, the Committee has used stock options with dividend equivalents and performance-accelerated restricted stock as the components of long-term incentive compensation. Options were granted every three years with three-year performance cycles. The options became exercisable automatically in nine years, but vesting was accelerated if the performance goals were met after three years. The size of the awards was based upon the executive's established pay grade, which took into consideration the job's internal value, based on overall complexity and responsibility, and external value as reflected in a market competitiveness comparison.

Effective in 2003, several changes are being made to the long-term incentive program as a result of the study discussed above. The Committee does not expect to make additional stock option or restricted stock grants under the 1997 Executive Long-Term Incentive Plan. The Committee will use performance shares, with dividend equivalents, as the form of long-term incentive compensation, beginning with grants in 2003. These awards are expected to be made annually and will be paid out, if earned, in Company common stock. The performance periods will generally be three years, and performance goals will compare Company performance against a peer group in specified areas. This new long-term award is designed to ensure the retention value and the motivation effect of the Company's long-term compensation program on the Company's executive officers.

All regular employees participate in the growth of the Company through the Option Award Program. Stock options were granted under this program to all employees in 1998 and in 2001.

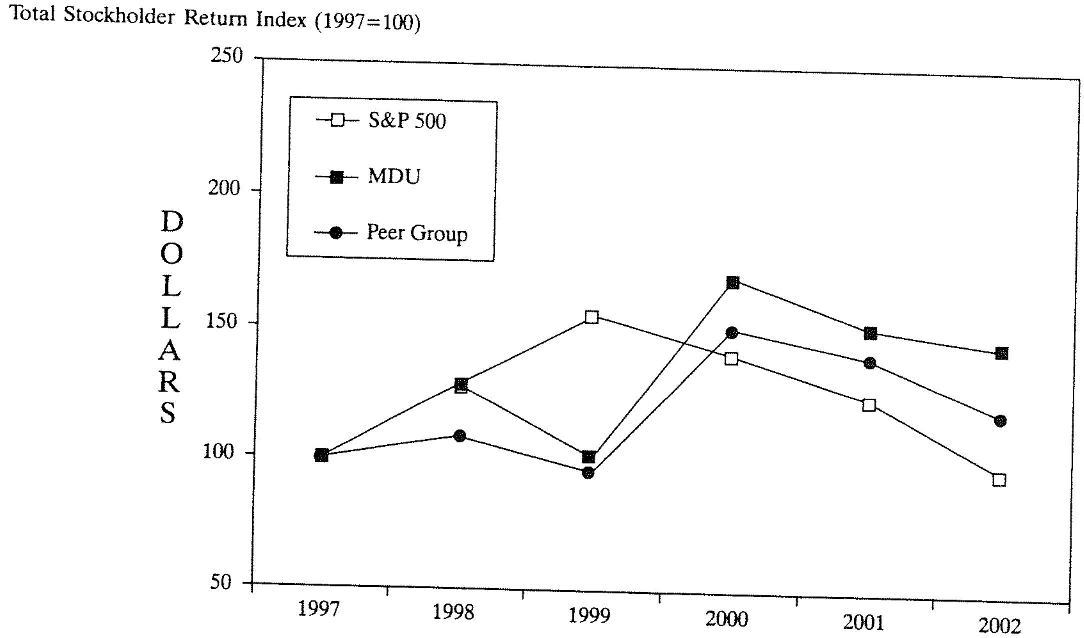
At December 31, 2002, there were approximately 3,240,845 million options outstanding under the Company's various plans, which is approximately 4.38% of shares outstanding.

In 1994, the Board of Directors adopted Stock Ownership Guidelines under which executives are required to own Company Common Stock valued from one to four times their annual salary.

The Committee monitors the impact of federal tax laws on executive compensation, including Section 162(m) of the Internal Revenue Code. The deductibility of some types of compensation depends upon the timing of an executive's vesting or exercise of awards or on whether such awards qualify as "performance-based" under the provisions of Section 162(m). The Committee will consider the possible tax effect when structuring performance-based compensation but may pay compensation to its executive officers that is not fully deductible.

Harry J. Pearce, Chairman
Thomas Everist, Member
Homer A. Scott, Member

MDU RESOURCES GROUP, INC.
COMPARISON OF FIVE YEAR TOTAL STOCKHOLDER RETURN (1)



	1997	1998	1999	2000	2001	2002
S&P 500	100.00	128.58	155.63	141.46	124.65	97.10
MDU	100.00	128.72	101.54	170.68	152.49	144.92
Peer Group	100.00	108.80	95.86	151.57	140.44	119.47

(1) All data is indexed to December 31, 1997, for the Company, the S&P 500, and the Peer Group. Total stockholder return is calculated using the December 31 price for each year. It is assumed that all dividends are reinvested in stock at the frequency paid, and the returns of each component peer issuer of the group is weighted according to the issuer's stock market capitalization at the beginning of the period.

Peer Group issuers are Allegheny Energy, Inc., Allete, Inc., Alliant Energy Corporation, Black Hills Corporation, Comstock Resources, Inc., Equitable Resources, Inc., Florida Rock Industries, Inc., Hanson PLC ADR, KeySpan Corporation (returns included for the full years of trading for 1999 through 2002), Kinder Morgan, Inc., Louis Dreyfus Natural Gas Corp. (returns included for the full years of trading for 1998 through 2000. Discontinued trading in 2001, the result of the acquisition by Dominion Resources, Inc.), Martin Marietta Materials, Inc., Newfield Exploration Company, NICOR, Inc., OGE Energy Corp., ONEOK, Inc., Peoples Energy Corporation, Pogo Producing Company, Quanta Services, Inc. (returns included for the full years of trading for 1999 through 2002), Questar Corporation, SCANA Corporation, Stone Energy Corporation, TECO Energy, Inc., UGI Corporation, Vectren Corporation (formerly Indiana Energy, Inc.), Vulcan Materials Company, and XTO Energy, Inc.(formerly Cross Timbers Oil Company).

BALANCE SHEET

Year: 2002

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	Utility Plant			
3	101 Gas Plant in Service	$197,090,940	$207,668,012	5.37%
4	101.1 Property Under Capital Leases			
5	102 Gas Plant Purchased or Sold			
6	104 Gas Plant Leased to Others	25,772	25,772	0.00%
7	105 Gas Plant Held for Future Use			
8	105.1 Production Properties Held for Future Use			
9	106 Completed Constr. Not Classified - Gas			
10	107 Construction Work in Progress - Gas	5,669,666	2,238,797	-60.51%
11	108 (Less) Accumulated Depreciation	(123,988,907)	(131,500,970)	6.06%
12	111 (Less) Accumulated Amortization & Depletion	(518,667)	(531,369)	2.45%
13	114 Gas Plant Acquisition Adjustments	13,942,794	13,942,794	0.00%
14	115 (Less) Accum. Amort. Gas Plant Acq. Adj.	(517,780)	(1,104,166)	113.25%
15	116 Other Gas Plant Adjustments			
16	117 Gas Stored Underground - Noncurrent	2,795,330	1,913,520	-31.55%
17	118 Other Utility Plant	616,121,210	640,284,477	3.92%
18	119 Accum. Depr. and Amort. - Other Utl. Plant	(347,258,370)	(363,347,129)	4.63%
19	**TOTAL Utility Plant**	$363,361,988	$369,589,738	1.71%
20	**Other Property & Investments**			
21	121 Nonutility Property	$140,013	$174,544	24.66%
22	122 (Less) Accum. Depr. & Amort. of Nonutil. Prop.	(36,353)	(79,695)	119.23%
23	123 Investments in Associated Companies			
24	123.1 Investments in Subsidiary Companies	956,558,029	1,130,703,822	18.21%
25	124 Other Investments	25,822,974	26,757,835	3.62%
26	125 Sinking Funds			
27	**TOTAL Other Property & Investments**	$982,484,663	$1,157,556,506	17.82%
28	**Current & Accrued Assets**			
29	131 Cash	$3,131,759	$5,959,888	90.30%
30	132-134 Special Deposits	1,200	1,200	0.00%
31	135 Working Funds	16,015	130,965	717.76%
32	136 Temporary Cash Investments	1,906,817	3,297,879	100.00%
33	141 Notes Receivable			
34	142 Customer Accounts Receivable	22,175,582	28,398,322	28.06%
35	143 Other Accounts Receivable	2,525,644	2,365,820	-6.33%
36	144 (Less) Accum. Provision for Uncollectible Accts.	(333,634)	(241,038)	-27.75%
37	145 Notes Receivable - Associated Companies			
38	146 Accounts Receivable - Associated Companies	12,316,880	16,147,799	31.10%
39	151 Fuel Stock	2,008,080	2,233,437	11.22%
40	152 Fuel Stock Expenses Undistributed			
41	153 Residuals and Extracted Products			
42	154 Plant Materials and Operating Supplies	5,758,377	5,894,011	2.36%
43	155 Merchandise	911,650	1,012,624	11.08%
44	156 Other Material & Supplies			
45	163 Stores Expense Undistributed			
46	164.1 Gas Stored Underground - Current	25,481,101	15,322,047	-39.87%
47	165 Prepayments	9,371,438	7,220,656	-22.95%
48	166 Advances for Gas Explor., Devl. & Production			
49	171 Interest & Dividends Receivable			
50	172 Rents Receivable			
51	173 Accrued Utility Revenues	19,354,571	20,628,893	6.58%
52	174 Miscellaneous Current & Accrued Assets	512,238	57,814	-88.71%
53	**TOTAL Current & Accrued Assets**	$105,137,718	$108,430,317	3.13%

BALANCE SHEET

Year: 2002

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits (cont.)**			
2				
3	**Deferred Debits**			
4				
5	181 Unamortized Debt Expense	$1,257,574	$1,123,696	-10.65%
6	182.1 Extraordinary Property Losses			
7	182.2 Unrecovered Plant & Regulatory Study Costs			
8	182.3 Other Regulatory Assets	3,470,463	3,651,680	5.22%
9	183 Prelim. Electric Survey & Investigation Chrg.	338,503	1,686,727	398.29%
10	183.1 Prelim. Nat. Gas Survey & Investigation Chrg.			
11	183.2 Other Prelim. Nat. Gas Survey & Invtg. Chrgs.			
12	184 Clearing Accounts	(22,715)	(40,451)	78.08%
13	185 Temporary Facilities			
14	186 Miscellaneous Deferred Debits	14,177,327	19,360,006	36.56%
15	187 Deferred Losses from Disposition of Util. Plant			
16	188 Research, Devel. & Demonstration Expend.			
17	189 Unamortized Loss on Reacquired Debt	6,829,294	5,627,511	-17.60%
18	190 Accumulated Deferred Income Taxes	19,215,849	20,176,715	5.00%
19	191 Unrecovered Purchased Gas Costs	(27,705,734)	(2,396,235)	-91.35%
20	192.1 Unrecovered Incremental Gas Costs			
21	192.2 Unrecovered Incremental Surcharges			
22	**TOTAL Deferred Debits**	$17,560,561	$49,189,649	180.11%
23				
24	**TOTAL ASSETS & OTHER DEBITS**	$1,468,544,930	$1,684,766,210	14.72%
	Account Number & Title	Last Year	This Year	% Change
25	**Liabilities and Other Credits**			
26				
27	**Proprietary Capital**			
28				
29	201 Common Stock Issued	$70,016,851	$74,282,038	6.09%
30	202 Common Stock Subscribed			
31	204 Preferred Stock Issued	16,400,000	16,300,000	-0.61%
32	205 Preferred Stock Subscribed			
33	207 Premium on Capital Stock	649,500,861	751,331,277	15.68%
34	211 Miscellaneous Paid-In Capital			
35	213 (Less) Discount on Capital Stock			
36	214 (Less) Capital Stock Expense	(2,980,351)	(3,236,160)	8.58%
37	216 Appropriated Retained Earnings	41,349,699	44,231,211	6.97%
38	216.1 Unappropriated Retained Earnings	353,291,342	430,566,718	21.87%
39	217 (Less) Reacquired Capital Stock			
40	219 Accumulated Other Comprehensive Income		(9,803,865)	
41	**TOTAL Proprietary Capital**	$1,127,578,402	$1,303,671,219	15.62%
42				
43	**Long Term Debt**			
44				
45	221 Bonds	$130,850,000	$130,850,000	0.00%
46	222 (Less) Reacquired Bonds			
47	223 Advances from Associated Companies			
48	224 Other Long Term Debt	27,500,000	52,000,000	89.09%
49	225 Unamortized Premium on Long Term Debt			
50	226 (Less) Unamort. Discount on Long Term Debt-Dr.	(45,561)	(41,116)	-9.76%
51	**TOTAL Long Term Debt**	$158,304,439	$182,808,884	15.48%

BALANCE SHEET

Year: 2002

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Total Liabilities and Other Credits (cont.)**			
3					
4	**Other Noncurrent Liabilities**				
5					
6	227	Obligations Under Cap. Leases - Noncurrent			
7	228.1	Accumulated Provision for Property Insurance			
8	228.2	Accumulated Provision for Injuries & Damages	$1,302,912	$1,415,463	8.64%
9	228.3	Accumulated Provision for Pensions & Benefits	18,445,259	24,086,968	30.59%
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds		67,067	
12		**TOTAL Other Noncurrent Liabilities**	$19,748,171	$25,569,498	29.48%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable	$0	$8,000,000	100.00%
17	232	Accounts Payable	15,329,149	18,828,269	22.83%
18	233	Notes Payable to Associated Companies			
19	234	Accounts Payable to Associated Companies	4,927,109	5,882,199	19.38%
20	235	Customer Deposits	1,463,945	1,472,979	0.62%
21	236	Taxes Accrued	16,841,333	(464,747)	-102.76%
22	237	Interest Accrued	2,256,546	2,212,959	-1.93%
23	238	Dividends Declared	16,108,133	17,959,379	11.49%
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	1,170,254	1,210,339	3.43%
27	242	Miscellaneous Current & Accrued Liabilities	9,892,517	10,489,414	6.03%
28	243	Obligations Under Capital Leases - Current			
29		**TOTAL Current & Accrued Liabilities**	$67,988,986	$65,590,791	-3.53%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	$1,702,961	$1,533,151	-9.97%
34	253	Other Deferred Credits	3,642,062	3,058,287	-16.03%
35	254	Other Regulatory Liabilities	9,261,453	14,584,248	57.47%
36	255	Accumulated Deferred Investment Tax Credits	16,324,041	15,563,924	-4.66%
37	256	Deferred Gains from Disposition Of Util. Plant			
38	257	Unamortized Gain on Reacquired Debt			
39	281-283	Accumulated Deferred Income Taxes	63,994,415	72,386,208	13.11%
40		**TOTAL Deferred Credits**	$94,924,932	$107,125,818	12.85%
41					
42	**TOTAL LIABILITIES & OTHER CREDITS**		$1,468,544,930	$1,684,766,210	14.72%

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NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 1
Summary of Significant Accounting Policies
Basis of presentation
The consolidated financial statements of MDU Resources Group, Inc. and its subsidiaries (Company) include the accounts of the following segments: electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production, construction materials and mining and independent power production. The electric and natural gas distribution segments and a portion of the pipeline and energy services segment are regulated. The Company's nonregulated operations include the utility services, natural gas and oil production, construction materials and mining, and independent power production segments, and a portion of the pipeline and energy services segment. For further descriptions of the Company's business segments, see Note 12. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generation stations.

The Company uses the equity method of accounting for its 49 percent interest in MPX Holdings, Ltda. (MPX), which was formed to develop electric generation and transmission, steam generation, power equipment and coal mining projects in Brazil. For more information on the Company's equity investment, see Note 2.

The Company's regulated businesses are subject to various state and federal agency regulation. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company's nonregulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Regulation" (SFAS No. 71). SFAS No. 71 requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 4 for more information regarding the nature and amounts of these regulatory deferrals.

Prior to the sale of the Company's coal operations as discussed in Note 12, intercompany coal sales, which were made at prices approximately the same as those charged to others, and the related utility fuel purchases were not eliminated in accordance with the provisions of SFAS No. 71. All other significant intercompany balances and transactions have been eliminated in consolidation.

Cash and cash equivalents
The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Allowance for doubtful accounts
The Company's allowance for doubtful accounts as of December 31, 2002 and 2001, was $8.2 million and $5.8 million, respectively.

Natural gas in underground storage
Natural gas in underground storage for the Company's regulated operations is carried at cost using the last-in, first-out method. The portion of the cost of natural gas in underground storage expected to be used within one year was included in inventories and amounted to $18.2 million and $28.6 million at December 31, 2002 and 2001, respectively. The remainder of natural gas in underground storage was included in property, plant and

equipment and was $42.2 million and $43.1 million at December 31, 2002 and 2001, respectively.

Inventories
Inventories, other than natural gas in underground storage for the Company's regulated operations, consisted primarily of materials and supplies of $23.0 million and $22.5 million, aggregates held for resale of $39.6 million and $31.1 million and other inventories of $12.3 million and $13.1 million as of December 31, 2002 and 2001, respectively. These inventories were stated at the lower of average cost or market.

Property, plant and equipment
Additions to property, plant and equipment are recorded at cost when first placed in service. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost and cost of removal, less salvage, is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for natural gas and oil production properties as described below, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize an allowance for funds used during construction (AFUDC) on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was $7.6 million, $6.6 million and $5.2 million in 2002, 2001 and 2000, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable reserves, which are depleted based on the units of production method based on recoverable deposits, and natural gas and oil production properties as described below.

Property, plant and equipment at December 31, 2002 and 2001, was as follows:

	2002	2001	Estimated Depreciable Life in Years
	(Dollars in thousands)		
Regulated:			
Electric:			
Electric generation, distribution and transmission plant	$ 619,230	$ 597,080	4-50
Natural gas distribution:			
Natural gas distribution plant(a)	246,844	238,566	4-40
Pipeline and energy services:			
Natural gas transmission, gathering and storage facilities (b)	303,245	294,237	3-70
Nonregulated:			
Utility services:			
Land	2,601	2,330	---
Buildings and improvements	8,768	4,586	10-40
Machinery, vehicles and equipment	54,833	46,090	2-10
Other	4,458	6,184	3-10
Pipeline and energy services:			
Natural gas gathering and other facilities	108,179	108,482	3-30
Energy services	1,270	7,330	3-15
Natural gas and oil production:			
Natural gas and oil properties	748,844	628,509	(c)
Other	6,944	2,317	5-7
Construction materials and mining:			

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NOTES TO FINANCIAL STATEMENTS (Continued)

Land	85,376	80,526	---
Buildings and improvements	43,144	43,069	3-39
Machinery, vehicles and equipment	493,349	412,856	3-20
Construction in progress	10,151	10,631	---
Depletable reserves	172,235	164,328	(d)
Independent power production:			
Electric generation	58,000	---	20-30
Other	36,525	---	3-20
Less accumulated depreciation, depletion and amortization	1,079,110	942,723	
Net property, plant and equipment	$ 1,924,886	$ 1,704,398	

(a) Includes natural gas in underground storage of $1.9 million and $2.8 million at December 31, 2002 and 2001, respectively, which is not subject to depreciation.
(b) Includes natural gas in underground storage of $40.3 million at December 31, 2002 and 2001, which is not subject to depreciation.
(c) Amortized on the units of production method based on total proved reserves.
(d) Depleted based on the units of production method based on recoverable deposits.

Impairment of long-lived assets
The Company reviews the carrying values of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In 2000, the Company experienced significant changes in market conditions at one of its energy marketing operations, which negatively affected the fair value of the assets at that operation. Due to the significance of the decline, the Company recorded an impairment charge of $3.9 million after tax in 2000. The amount related to this impairment is included in depreciation, depletion and amortization. Excluding this impairment, no other long-lived assets have been impaired and, accordingly, no other impairment losses have been recorded in 2002, 2001 and 2000. Unforeseen events and changes in circumstances could require the recognition of other impairment losses at some future date.

Goodwill
Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. On January 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangibles" (SFAS No. 142) and ceased amortization of its goodwill. Goodwill is required to be tested for impairment annually, or more frequently if events or changes in circumstances indicate that goodwill may be impaired. In accordance with SFAS No. 142, the Company performed its transitional goodwill impairment testing as of January 1, 2002, and performed its annual goodwill impairment testing as of October 31, 2002, and determined that no impairments existed at those dates. For more information on goodwill and the adoption of SFAS No. 142, see Note 3 and new accounting standards in Note 1 as discussed below.

Impairment testing of natural gas and oil properties
The Company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units of production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future

net revenues of proved reserves based on single point in time spot market prices, as mandated under the rules of the Securities and Exchange Commission, and the lower of cost or fair value of unproved properties. Future net revenue is estimated based on end-of-quarter spot market prices adjusted for contracted price changes. If capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter unless subsequent price changes eliminate or reduce an indicated write-down.

At December 31, 2002 and 2001, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to December 31, 2002, could result in a future write-down of the Company's natural gas and oil properties.

Revenue recognition
Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is probable. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed below. The Company recognizes revenue from natural gas and oil production activities only on that portion of production sold and allocable to the Company's ownership interest in the related well. The Company recognizes all other revenues when services are rendered or goods are delivered.

Percentage-of-completion method
The Company recognizes construction contract revenue from fixed price and modified fixed price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. Costs in excess of billings on uncompleted contracts of $19.4 million and $29.7 million for the years ended December 31, 2002 and 2001, respectively, represents revenues recognized in excess of amounts billed and was included in receivables, net. Billings in excess of costs on uncompleted contracts of $24.5 million and $17.3 million for the years ended December 31, 2002 and 2001, respectively, represents billings in excess of revenues recognized and was included in accounts payable. Also included in receivables, net were amounts representing balances billed but not paid by customers under retainage provisions in contracts that amounted to $25.6 million and $20.5 million as of December 31, 2002 and 2001, respectively.

Derivative instruments
The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions, and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties. The Company's policy requires settlement of natural gas and oil price derivative instruments monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. These policies and procedures include an evaluation of potential counterparties' credit ratings and credit exposure limitations. Accordingly, the Company does not anticipate any material effect to its financial position or results of operations as a result of nonperformance by counterparties.

Advertising

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The Company expenses advertising costs as incurred, and the amount of advertising expense for the years 2002, 2001 and 2000, was $3.4 million, $2.9 million and $2.0 million, respectively.

Natural gas costs recoverable or refundable through rate adjustments
Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 24 months to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments amounted to $2.4 million and $27.7 million at December 31, 2002 and 2001, respectively, and are included in other accrued liabilities.

Insurance
Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $500,000 per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $500,000 per accident or occurrence. These subsidiaries have excess coverage on a per occurrence basis beyond the deductible levels. The subsidiaries of the Company are insuring for losses up to the deductible amounts, which are accrued based on estimates of the liability for claims incurred and an estimate of claims incurred but not reported.

Income taxes
The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities resulting from the Company's adoption of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes," have been recorded as a regulatory liability and are included in other accrued liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Foreign currency translation adjustment
The functional currency of the Company's investment in a 200-megawatt natural gas-fired power plant in Brazil, as further discussed in Note 2, is the Brazilian real. Translation from the Brazilian real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses have been translated using the weighted average exchange rate for each month prevailing during the period reported. Adjustments resulting from such translations are reported as a separate component of other comprehensive income in common stockholders' equity.

Transaction gains and losses resulting from the effect of exchange rate changes on transactions denominated in a currency other than the functional currency of the reporting entity are recorded in income.

Earnings per common share
Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options and restricted stock grants. For the years ended

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December 31, 2002 and 2001, 2,449,950 shares and 150,630 shares, respectively, with an average exercise price of $30.13 and $36.86, respectively, attributable to the exercise of outstanding options, were excluded from the calculation of diluted earnings per share because their effect was antidilutive. For the year ended December 31, 2000, there were no shares excluded from the calculation of diluted earnings per share. For the years ended December 31, 2002, 2001 and 2000, no adjustments were made to reported earnings in the computation of earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

Stock-based compensation
The Company has stock option plans for directors, key employees and employees and accounts for these option plans in accordance with Accounting Principles Board (APB) Opinion No. 25 under which no compensation cost has been recognized. For more information on the Company's stock-based compensation, see Note 10.

The following table illustrates the effect on earnings and earnings per common share for the years ended December 31, 2002, 2001 and 2000, as if the Company had applied Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123) to its stock-based compensation:

	2002	2001	2000
	(In thousands, except per share amounts)		
Earnings on common stock, as reported	$ 147,688	$ 155,087	$ 110,262
Total stock-based compensation expense determined under fair value method for all awards, net of related tax effects	(2,862)	(3,799)	(529)
Pro forma earnings on common stock	$ 144,826	$ 151,288	$ 109,733
Earnings per common share:			
Basic -- as reported	$ 2.09	$ 2.31	$ 1.80
Basic -- pro forma	$ 2.05	$ 2.25	$ 1.80
Diluted -- as reported	$ 2.07	$ 2.29	$ 1.80
Diluted -- pro forma	$ 2.03	$ 2.23	$ 1.79

Use of estimates
The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of long-lived assets, goodwill and natural gas and oil properties; fair values of acquired assets and liabilities under the purchase method of accounting; natural gas and oil reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; the valuation of stock-based compensation; and the fair value of an embedded derivative in a power purchase agreement related to an equity method investment in Brazil, as discussed in Note 2. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information
Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	2002	2001	2000

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Interest, net of amount capitalized	$37,788	$42,267	$41,912
Income taxes	$60,988	$75,284	$30,930

Reclassifications
Certain reclassifications have been made in the financial statements for prior years to conform to the current presentation. Such reclassifications had no effect on net income or stockholders' equity as previously reported.

New accounting standards
In June 2001, the Financial Accounting Standards Board (FASB) approved SFAS No. 142. SFAS No. 142 changes the accounting for goodwill and intangible assets and requires that goodwill no longer be amortized but be tested for impairment at least annually at the reporting unit level in accordance with SFAS No. 142. Recognized intangible assets with determinable useful lives should be amortized over their useful lives and reviewed for impairment in accordance with Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." For more information on the adoption of SFAS No. 142, see Note 3.

In June 2001, the FASB approved Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for the recorded amount or incurs a gain or loss upon settlement. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002.

The Company has identified certain asset retirement obligations that will be subject to the standard and adopted SFAS No. 143 on January 1, 2003. These obligations include the plugging and abandonment of natural gas and oil wells; decommissioning of certain electric generating facilities; reclamation of certain aggregate properties; removal of certain natural gas distribution, transmission, storage and gathering facilities, and certain other obligations associated with leased properties. Certain natural gas distribution, transmission, storage and gathering facilities have been determined to have indeterminate useful lives. The adoption of SFAS No. 143 is expected to result in a one-time cumulative effect after-tax charge to earnings in the range of $7.0 million to $10.0 million and also is estimated to reduce 2003 earnings before the cumulative effect charge by approximately $1.6 million to $2.1 million. In addition, a regulatory asset that is approximated to be less than $1.0 million will be recognized for the transition amount that is expected to be recovered in rates over time. The Company intends to record the cumulative charge and regulatory asset in the first quarter of 2003.

In April 2002, the FASB approved Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (SFAS No. 145). FASB No. 4 required all gains or losses from extinguishment of debt to be classified as extraordinary items net of income taxes. SFAS No. 145 requires that gains and losses from extinguishment of debt be evaluated under the provisions of APB Opinion No. 30, and be classified as ordinary items unless they are unusual or infrequent or meet the specific criteria for treatment as an extraordinary item. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002. The Company believes the adoption of SFAS No. 145 will not have a material effect on its financial position or results of operations.

In June 2002, the FASB approved Statement of Financial Accounting Standards No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" (SFAS No. 146). SFAS

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NOTES TO FINANCIAL STATEMENTS (Continued)

No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)" (EITF No. 94-3). SFAS No. 146 requires recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan under EITF No. 94-3. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002, and is not expected to have a material effect on the Company's financial position or results of operations.

In September 2002, the Emerging Issues Task Force (EITF) reached a consensus in EITF Issue No. 02-13, "Deferred Income Tax Considerations in Applying the Goodwill Impairment Test in FASB Statement No. 142, Goodwill and Other Intangible Assets" (EITF No. 02-13) that the determination of whether to estimate the fair value of a reporting unit by assuming that the unit could be bought or sold in a nontaxable transaction versus a taxable transaction is a matter of judgment that depends on the relevant facts and circumstances. The EITF also reached the consensus that deferred income taxes should be included in the carrying value of the reporting unit, regardless of whether the fair value of the reporting unit will be determined assuming it would be bought or sold in a taxable or nontaxable transaction. In addition, EITF No. 02-13 states that for purposes of determining the implied fair value of a reporting unit's goodwill, an entity should use the income tax bases of a reporting unit's assets and liabilities implicit in the tax structure assumed in its estimation of fair value of the reporting unit. EITF No. 02-13 did not have a material effect on the Company's goodwill impairment testing.

In October 2002, the EITF reached a consensus in EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF No. 02-3) to rescind EITF Issue No. 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF No. 98-10). The impact of the rescission of EITF No. 98-10 is to preclude mark-to-market accounting for all energy trading contracts not within the scope of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended, (SFAS No. 133). In addition, the EITF reached a consensus that gains and losses on derivative instruments within the scope of SFAS No. 133 should be shown net in the income statement if the derivative instruments are held for trading purposes. The adoption of EITF No. 02-3 and rescission of EITF No. 98-10 did not have a material effect on the Company's financial position or results of operations.

In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (Interpretation No. 45). Interpretation No. 45 clarifies the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. Interpretation No. 45 also requires a guarantor to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing certain types of guarantees. Certain types of guarantees are not subject to the initial recognition and measurement provisions of Interpretation No. 45 but are subject to its disclosure requirements. The initial recognition and initial measurement provisions of Interpretation No. 45 are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, regardless of the guarantor's fiscal year-end. The guarantor's previous accounting for guarantees issued prior to the date of the initial application of Interpretation No. 45 shall not be revised or restated. The disclosure requirements in Interpretation No. 45 are effective for financial statements of interim or annual periods ended after December 15, 2002. The Company will apply the initial recognition and initial measurement provisions of Interpretation No. 45 to guarantees issued or modified after December 31, 2002. For more information on the Company's guarantees and the disclosure requirements of Interpretation

No. 45, as applicable to the Company, see Note 17.

In December 2002, the FASB approved Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of FASB Statement No. 123" (SFAS No. 148). SFAS No. 148 amends SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002. The Company had adopted the disclosure provisions of SFAS No. 148 at December 31, 2002.

Comprehensive income
Comprehensive income is the sum of net income as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains and losses on derivative instruments qualifying as hedges, a minimum pension liability adjustment and a foreign currency translation adjustment.

The components of other comprehensive income (loss) and their related tax effects for the years ended December 31, 2002, 2001 and 2000, were as follows:

	2002	2001 (In thousands)	2000
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Unrealized loss on derivative instruments at January 1, 2001, due to cumulative effect of a change in accounting principle, net of tax of $3,970 in 2001	$ ---	$ (6,080)	$ ---
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $2,903 and $1,448 in 2002 and 2001, respectively	(4,541)	2,218	---
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $1,448 and $3,970 in 2002 and 2001, respectively	2,218	(6,080)	---
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(6,759)	2,218	---
Minimum pension liability adjustment, net of tax of $2,876 in 2002	(4,464)	---	---
Foreign currency translation adjustment	(799)	---	---
Total other comprehensive income (loss)	$ (12,022)	$ 2,218	$ ---

The after-tax components of accumulated other comprehensive income (loss) as of December

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31, 2002, 2001 and 2000, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Minimum Pension Liability Adjustment	Foreign Currency Translation Adjustment	Total Accumulated Other Comprehensive Income (Loss)
		(In thousands)		
Balance at December 31, 2000	$ ---	$ ---	$ ---	$ ---
Balance at December 31, 2001	$ 2,218	$ ---	$ ---	$ 2,218
Balance at December 31, 2002	$(4,541)	$(4,464)	$ (799)	$ (9,804)

NOTE 2
Equity Method Investment
In August 2001, a Brazilian subsidiary of the Company entered into a joint venture agreement with a Brazilian firm under which the parties have formed MPX. This subsidiary has a 49 percent interest in MPX. MPX, through a wholly owned subsidiary, has constructed a 200-megawatt natural gas-fired power plant (Project) in the Brazilian state of Ceara. The first 100 megawatts entered commercial service in July 2002, and the second 100 megawatts entered commercial service in January 2003. Petrobras, the partially Brazilian state-owned energy company, has agreed to purchase all of the capacity and market all of the Project's energy. Petrobras commenced making capacity payments in the third quarter of 2002. The power purchase agreement with Petrobras expires in May 2008. Petrobras also is under contract for five years to supply natural gas to the Project. This contract is renewable for an additional 13 years. The functional currency for the Project is the Brazilian real. The power purchase agreement with Petrobras contains an embedded derivative, which derives its value from an annual adjustment factor, which largely indexes the contract capacity payments to the U.S. dollar. At December 31, 2002, the Company's 49 percent share of the gain from the embedded derivative in the power purchase agreement was $13.6 million (after tax). In addition, the Company's 49 percent share of the foreign currency losses resulting from devaluation of the Brazilian real totaled $9.4 million (after tax) for the year ended December 31, 2002.

The Company's investment in the Project has been accounted for under the equity method of accounting, and the Company's share of net income for the year ended December 31, 2002, was included in other income - net. At December 31, 2002 and 2001, the Company's investment in the Project was approximately $27.8 million and $23.8 million, respectively.

NOTE 3
Goodwill and Other Intangible Assets
The Company adopted SFAS No. 142, as discussed in Note 1, on January 1, 2002. The Company completed its transitional goodwill impairment testing as of January 1, 2002, and performed its annual goodwill impairment testing as of October 31, 2002, and determined that no impairments existed at those dates. Therefore, no impairment loss has been recorded for the year ended December 31, 2002.

On January 1, 2002, in accordance with SFAS No. 142, the Company ceased amortization of its goodwill recorded in business combinations that occurred on or before June 30, 2001. The following information is presented as if SFAS No. 142 was adopted as of January 1, 2000. The reconciliation of previously reported earnings and earnings per common share to the amounts adjusted for the exclusion of goodwill amortization, net of the related income tax effects, for the years ended December 31, 2002, 2001 and 2000, were as follows:

	2002	2001	2000
	(In thousands, except per share amounts)		

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Reported earnings on common stock	$ 147,688	$155,087	$110,262
Add: Goodwill amortization, net of tax	---	3,649	2,741
Adjusted earnings on common stock	$ 147,688	$158,736	$113,003
Reported earnings per common share -- basic	$ 2.09	$ 2.31	$ 1.80
Add: Goodwill amortization, net of tax	---	.05	.05
Adjusted earnings per common share -- basic	$ 2.09	$ 2.36	$ 1.85
Reported earnings per common share -- diluted	$ 2.07	$ 2.29	$ 1.80
Add: Goodwill amortization, net of tax	---	.05	.04
Adjusted earnings per common share -- diluted	$ 2.07	$ 2.34	$ 1.84

The changes in the carrying amount of goodwill for the year ended December 31, 2002, by business segment were as follows:

	Balance as of January 1, 2002	Goodwill Acquired During the Year (In thousands)	Balance as of December 31, 2002
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Utility services	61,909	578	62,487
Pipeline and energy services	9,336	158	9,494
Natural gas and oil production	---	---	---
Construction materials and mining	102,752	9,135	111,887
Independent power production	---	7,131	7,131
Total	$ 173,997	$ 17,002	$ 190,999

Other intangible assets at December 31, 2002 and 2001, were as follows:

	2002 (In thousands)	2001
Amortizable intangible assets:		
Leasehold rights	$ 172,496	$ 164,446
Accumulated amortization	(7,494)	(4,896)
	165,002	159,550
Noncompete agreements	12,075	12,034
Accumulated amortization	(9,366)	(8,811)
	2,709	3,223
Other	7,224	1,377
Accumulated amortization	(374)	(172)
	6,850	1,205
Unamortizable intangible assets	1,603	---
Total	$ 176,164	$ 163,978

Amortization expense for amortizable intangible assets for the year ended December 31, 2002, was $3.4 million. Estimated amortization expense for amortizable intangible assets is $404 million in 2003, $4.3 million in 2004, $4.4 million in 2005, $3.1 million in 2006, $3.1 million in 2007 and $155.3 million thereafter.

NOTE 4

Regulatory Assets and Liabilities

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	2002	2001
	(In thousands)	
Regulatory assets:		
Long-term debt refinancing costs	$ 5,627	$ 6,829
Deferred income taxes	4,230	13,417
Plant costs	2,330	2,499
Postretirement benefit costs	616	722
Other	4,788	5,929
Total regulatory assets	17,591	29,396
Regulatory liabilities:		
Taxes refundable to customers	11,699	12,318
Reserves for regulatory matters	9,856	7,132
Plant decommissioning costs	8,879	8,243
Deferred income taxes	5,491	5,661
Natural gas costs refundable through rate adjustments	2,396	27,706
Other	2,779	5,053
Total regulatory liabilities	41,100	66,113
Net regulatory position	$ (23,509)	$ (36,717)

As of December 31, 2002, substantially all of the Company's regulatory assets, other than certain deferred income taxes, were being reflected in rates charged to customers and are being recovered over the next one to 20 years.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of SFAS No. 71 occurs.

NOTE 5

Derivative Instruments

The Company adopted SFAS No. 133 on January 1, 2001. SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

SFAS No. 133 requires that as of the date of initial adoption, the difference between the fair market value of derivative instruments recorded on the balance sheet and the previous carrying amount of those derivative instruments be reported in net income or other comprehensive income (loss), as appropriate, as the cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20, "Accounting Changes." On January 1, 2001, the Company reported a net-of-tax cumulative-effect adjustment of $6.1 million in accumulated other comprehensive loss to recognize at fair value all derivative

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instruments that are designated as cash flow hedging instruments, which the Company reclassified into earnings during the year ended December 31, 2001. The transition to SFAS No. 133 did not have an effect on the Company's net income at adoption.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; or if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting will be discontinued, and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity.

As of December 31, 2002, certain subsidiaries of the Company held derivative instruments designated as cash flow hedging instruments, and a foreign currency derivative that was not designated as a hedge.

Hedging activities
A subsidiary of the Company utilizes natural gas and oil price swap and collar agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil on the subsidiary's forecasted sales of natural gas and oil production. Centennial Energy Holdings, Inc. (Centennial), a wholly owned subsidiary of the Company, entered into an interest rate swap agreement that expired in the fourth quarter of 2001. The objective for holding the interest rate swap agreement was to manage a portion of Centennial's interest rate risk on the forecasted issuance of fixed-rate debt under Centennial's commercial paper program. Each of the natural gas and oil price swap and collar agreements were designated as a hedge of the forecasted sale of natural gas and oil production and Centennial designated the interest rate swap agreement as a hedge of the risk of changes in interest rates on Centennial's forecasted issuances of fixed-rate debt under Centennial's commercial paper program.

On an ongoing basis, the balance sheet is adjusted to reflect the current fair market value of the swap and collar agreements. The related gains or losses on these agreements are recorded in common stockholders' equity as a component of other comprehensive income (loss). At the date the underlying transaction occurs, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the years ended December 31, 2002 and 2001, these subsidiaries of the Company recognized the ineffectiveness of cash flow hedges, which is included in operating revenues and interest expense for the natural gas and oil price swap and collar agreements and the interest rate swap agreement, respectively. For the years ended December 31, 2002 and 2001, the amount of hedge ineffectiveness recognized was immaterial. For the years ended December 31, 2002 and 2001, these subsidiaries did not exclude any components of the derivative instruments' gain or loss from the assessment of hedge effectiveness and there were no reclassifications into earnings as a result of the discontinuance of hedges.

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Gains and losses on derivative instruments that are reclassified from accumulated other comprehensive income (loss) to current-period earnings are included in the line item in which the hedged item is recorded. As of December 31, 2002, the maximum term of the subsidiary's swap and collar agreements, in which the subsidiary of the Company is hedging its exposure to the variability in future cash flows for forecasted transactions, is 12 months. The subsidiary of the Company estimates that over the next 12 months net losses of approximately $4.5 million will be reclassified from accumulated other comprehensive loss into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

Foreign currency derivative
On August 12, 2002, an indirect wholly owned Brazilian subsidiary of the Company entered into a foreign currency collar agreement for a notional amount of $21.3 million with a fixed price floor of R$3.10 and a fixed price ceiling of R$3.40 to manage a portion of its foreign currency risk. A subsidiary of the Company has a 49 percent equity investment in a 200-megawatt natural gas-fired electric generation project in Brazil, which has a portion of its borrowings and payables denominated in U.S. dollars. The Company's Brazilian subsidiary has exposure to currency exchange risk as a result of fluctuations in currency exchange rates between the U.S. dollar and the Brazilian real. The term of the collar agreement is from August 12, 2002, through February 3, 2003, and the collar agreement settles on February 3, 2003.

The foreign currency collar agreement has not been designated as a hedge and is recorded at fair value on the Consolidated Balance Sheets. Gains or losses on this derivative instrument are recorded in other income - net. The Company recorded a gain of $566,000 (after tax) on the foreign currency collar agreement for the year ended December 31, 2002.

Energy marketing
The Company had entered into other derivative instruments that were not designated as hedges in its energy marketing operations. In the third quarter of 2001, the Company sold the vast majority of its energy marketing operations. Net unrealized gains and losses on these derivative instruments were not material for the years ended December 31, 2001 and 2000.

NOTE 6
Fair Value of Other Financial Instruments
The estimated fair value of the Company's long-term debt and preferred stock subject to mandatory redemption is based on quoted market prices of the same or similar issues. The estimated fair values of the Company's natural gas and oil price swap and collar agreements were included in current liabilities and current assets at December 31, 2002 and 2001, respectively. The estimated fair value of the Company's foreign currency collar agreement was included in current assets at December 31, 2002. The estimated fair values of the Company's natural gas and oil price swap and collar agreements and foreign currency collar agreement reflect the estimated amounts the Company would receive or pay to terminate the contracts at the reporting date based upon quoted market prices of comparable contracts. The estimated fair value of the Company's long-term debt, preferred stock subject to mandatory redemption, natural gas and oil price swap and collar agreements and foreign currency collar agreement at December 31 was as follows:

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	$ 841,641	$ 888,066	$ 794,794	$ 816,988
Preferred stock subject to mandatory redemption	$ 1,300	$ 1,168	$ 1,400	$ 1,217

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Natural gas and oil price swap and collar agreements	$ (7,444)	$ (7,444)	$ 3,667	$ 3,667
Foreign currency collar agreement	$ 903	$ 903	$ ---	$ ---

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities (excluding unsettled derivative instruments) approximate their fair values because of their short-term nature.

NOTE 7
Short-term Borrowings
MDU Resources Group, Inc.
MDU Resources Group, Inc. (MDU Resources) has unsecured short-term bank lines of credit from several banks totaling $46 million and a revolving credit agreement with various banks totaling $50 million at December 31, 2002. The bank lines of credit provide for commitment fees at varying rates and there were no amounts outstanding under the bank lines of credit or the credit agreement at December 31, 2002 or 2001. The bank lines of credit and the credit agreement support MDU Resources' $75 million commercial paper program. Under the MDU Resources commercial paper program, $58.0 million was outstanding at December 31, 2002, of which $8.0 million was classified as short-term borrowings and $50.0 million was classified as long-term debt. There were no amounts outstanding under MDU Resources' commercial paper program at December 31, 2001. The commercial paper borrowings classified as short term are supported by the short-term bank lines of credit. The commercial paper borrowings classified as long-term debt (see Note 8) are intended to be refinanced on a long-term basis through continued MDU Resources commercial paper borrowings supported by the credit agreement, which allows for subsequent borrowings up to a term of one year. MDU Resources intends to renew or replace the existing credit agreement, which expires December 30, 2003.

In order to borrow under MDU Resources' credit agreement, MDU Resources must be in compliance with the applicable covenants and certain other conditions. The significant covenants include maximum leverage ratios, minimum interest coverage ratio, limitation on sale of assets and limitation on investments. MDU Resources was in compliance with these covenants and met the required conditions at December 31, 2002.

Currently, there are no credit facilities that contain cross-default provisions between MDU Resources and any of its subsidiaries.

International operations
A subsidiary of the Company, which has an investment in electric generating facilities in Brazil, has a short-term credit agreement that allows for borrowings of up to $25 million. Under this agreement, $12.0 million was outstanding at December 31, 2002, and there were no amounts outstanding at December 31, 2001. This subsidiary intends to renew this credit agreement, which expires June 30, 2003.

In order to borrow under the credit facility, the subsidiary must be in compliance with the applicable covenants and certain other conditions. The significant covenants include limitation on sale of assets and limitation on loans and investments. This subsidiary was in compliance with these covenants and met the required conditions at December 31, 2002.

NOTE 8
Long-term Debt and Indenture Provisions
Long-term debt outstanding at December 31 was as follows:

	2002	2001
	(In thousands)	
First mortgage bonds and notes:		

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Pollution Control Refunding Revenue Bonds, Series 1992, 6.65%, due June 1, 2022	$ 20,850	$ 20,850
Secured Medium-Term Notes, Series A at a weighted average rate of 7.59%, due on dates ranging from October 1, 2004 to April 1, 2012	110,000	110,000
Total first mortgage bonds and notes	130,850	130,850
Senior notes at a weighted average rate of 6.90%, due on dates ranging from May 4, 2003 to October 30, 2018	549,100	405,200
Commercial paper at a weighted average rate of 1.47%, supported by revolving credit agreements	151,900	219,700
Revolving line of credit, expired December 31, 2002	---	25,000
Term credit agreements at a weighted average rate of 7.08%, due on dates ranging from January 3, 2003 to December 1, 2013	7,873	11,769
Pollution control note obligation, 6.20%, due March 1, 2004	2,000	2,500
Discount	(82)	(225)
Total long-term debt	841,641	794,794
Less current maturities	22,083	11,085
Net long-term debt	$ 819,558	$ 783,709

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2002, aggregate $22.1 million in 2003; $173.8 million in 2004; $70.3 million in 2005; $100.2 million in 2006; $105.4 million in 2007 and $369.8 million thereafter.

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2002.

MDU Resources Group, Inc.
As discussed in Note 7, MDU Resources has a revolving credit agreement with various banks that supports $50 million of its $75 million commercial paper program.

At December 31, 2001, there was $25.0 million outstanding under a previous revolving line of credit.

MDU Resources' issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its Indenture of Mortgage. Generally, those restrictions require MDU Resources to pledge $1.43 of unfunded property to the trustee for each dollar of indebtedness incurred under the Indenture and that annual earnings (pretax and before interest charges), as defined in the Indenture, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the two tests, as of December 31, 2002, MDU Resources could have issued approximately $327 million of additional first mortgage bonds.

Centennial Energy Holdings, Inc.
Centennial has a revolving credit agreement with various banks that supports $305 million of Centennial's $350 million commercial paper program. There were no outstanding

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borrowings under the Centennial credit agreement at December 31, 2002 and 2001. Under the Centennial commercial paper program, $101.9 million and $219.7 million were outstanding at December 31, 2002 and 2001, respectively. The Centennial commercial paper borrowings are classified as long term as Centennial intends to refinance these borrowings on a long-term basis through continued Centennial commercial paper borrowings and as further supported by the Centennial credit agreement, which allows for subsequent borrowings up to a term of one year. Centennial intends to renew the Centennial credit agreement, which expires September 26, 2003.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $400 million. Under the terms of the master shelf agreement, $360.6 million was outstanding at December 31, 2002, and $210.0 million was outstanding at December 31, 2001. The amount outstanding under the uncommitted long-term master shelf agreement is included in senior notes in the preceding long-term debt table.

In order to borrow under Centennial's credit agreement and the Centennial uncommitted long-term master shelf agreement, Centennial and certain of its subsidiaries must be in compliance with the applicable covenants and certain other conditions. The significant covenants include maximum capitalization ratios, minimum interest coverage ratios, minimum consolidated net worth, limitation on priority debt, limitation on sale of assets and limitation on loans and investments. Centennial and such subsidiaries were in compliance with these covenants and met the required conditions at December 31, 2002.

The Centennial credit agreement and the Centennial uncommitted long-term master shelf agreement contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the Centennial credit agreement and the Centennial uncommitted long-term master shelf agreement will be in default. The Centennial credit agreement, the Centennial uncommitted long-term master shelf agreement and Centennial's practice limit the amount of subsidiary indebtedness.

Williston Basin Interstate Pipeline Company

Williston Basin Interstate Pipeline Company (Williston Basin), an indirect wholly owned subsidiary of the Company, has an uncommitted long-term master shelf agreement that allows for borrowings of up to $100 million. Under the terms of the master shelf agreement, $30.0 million was outstanding at December 31, 2002.

In order to borrow under Williston Basin's uncommitted long-term master shelf agreement, it must be in compliance with the applicable covenants and certain other conditions. The significant covenants include limitation on consolidated indebtedness, limitation on priority debt, limitation on sale of assets and limitation on investments. Williston Basin was in compliance with these covenants and met the required conditions at December 31, 2002.

NOTE 9

Preferred Stocks

Preferred stocks at December 31 were as follows:

	2002	2001
	(Dollars in thousands)	
Authorized:		
Preferred --		
500,000 shares, cumulative,		
par value $100, issuable in series		
Preferred stock A --		
1,000,000 shares, cumulative, without par		

value, issuable in series (none outstanding)		
Preference --		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
Subject to mandatory redemption --		
Preferred --		
5.10% Series - 13,000 shares in 2002 and 14,000 shares in 2001	$ 1,300	$ 1,400
Other preferred stock --		
4.50% Series -- 100,000 shares	10,000	10,000
4.70% Series -- 50,000 shares	5,000	5,000
	15,000	15,000
Total preferred stocks	16,300	16,400
Less sinking fund requirements	100	100
Net preferred stocks	$ 16,200	$ 16,300

The preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date on certain series of preferred stock.

The Company is obligated to make annual sinking fund contributions to retire the 5.10% Series preferred stock. The redemption prices and sinking fund requirements, where applicable, are summarized below:

Series	Redemption Price (a)	Sinking Fund Shares	Sinking Fund Price (a)
Preferred stocks:			
4.50%	$105 (b)	---	---
4.70%	$102 (b)	---	---
5.10%	$102	1,000 (c)	$100

(a) Plus accrued dividends.
(b) These series are redeemable at the sole discretion of the Company.
(c) Annually on December 1, if tendered.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The aggregate annual sinking fund amount applicable to preferred stock subject to mandatory redemption is $100,000 for each of the five years following December 31, 2002, and $800,000 thereafter.

NOTE 10
Common Stock
At the Annual Meeting of Stockholders held on April 23, 2002, the Company's common stockholders approved an amendment to the Certificate of Incorporation increasing the authorized number of common shares from 150 million shares to 250 million shares with a par value of $1.00 per share.

The Company's Automatic Dividend Reinvestment and Stock Purchase Plan (Stock Purchase Plan) provides participants the opportunity to invest all or a portion of their cash dividends in shares of the Company's common stock and to make optional cash payments for the same purpose. Holders of all classes of the Company's capital stock; legal residents in any of the 50 states; and beneficial owners, whose shares are held by brokers or other nominees through participation by their brokers or nominees, are eligible to participate in the Stock Purchase Plan. The Company's 401(k) Retirement Plan (K-Plan), is partially funded with the Company's common stock. Since January 1, 2000, the Stock Purchase Plan and K-Plan, with respect to Company stock, have been funded by the purchase of shares of common stock on the open market. At December 31, 2002, there were 8.1 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

In November 1998, the Company's Board of Directors declared, pursuant to a stockholders' rights plan, a dividend of one preference share purchase right (right) for each outstanding share of the Company's common stock. Each right becomes exercisable, upon the occurrence of certain events, for one one-thousandth of a share of Series B Preference Stock of the Company, without par value, at an exercise price of $125 per one one-thousandth, subject to certain adjustments. The rights are currently not exercisable and will be exercisable only if a person or group (acquiring person) either acquires ownership of 15 percent or more of the Company's common stock or commences a tender or exchange offer that would result in ownership of 15 percent or more. In the event the Company is acquired in a merger or other business combination transaction or 50 percent or more of its consolidated assets or earnings power are sold, each right entitles the holder to receive, upon the exercise thereof at the then current exercise price of the right multiplied by the number of one one-thousandth of a Series B Preference Stock for which a right is then exercisable, in accordance with the terms of the rights agreement, such number of shares of common stock of the acquiring person having a market value of twice the then current exercise price of the right. The rights, which expire on December 31, 2008, are redeemable in whole, but not in part, for a price of $.01 per right, at the Company's option at any time until any acquiring person has acquired 15 percent or more of the Company's common stock.

The Company has stock option plans for directors, key employees and employees, that grant options to purchase shares of the Company's stock. The Company accounts for these option plans in accordance with APB Opinion No. 25 under which no compensation expense has been recognized. The option exercise price is the market value of the stock on the date of grant. Options granted to the key employees automatically vest after nine years, but the plan provides for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expire 10 years after the date of grant. Options granted to directors and employees vest at date of grant and three years after date of grant, respectively, and expire 10 years after the date of grant. In addition, the Company has granted restricted stock awards under a long-term incentive plan, deferred compensation agreements and a restricted stock agreement totaling 350,392 shares and 348,021 shares in 2001 and 2000, respectively. The restricted stock awards granted vest to the participants at various times ranging from two years to nine years from date of issuance, but certain grants may vest early based upon the attainment of certain performance goals or upon a change in control of the Company. The weighted average grant date fair value of the restricted stock grants was $31.55 and $20.81 in 2001 and 2000, respectively. The Company also has granted stock awards totaling 14,260 shares, 12,673 shares and 7,582 shares in 2002, 2001 and 2000, respectively, under a nonemployee director stock compensation plan. The weighted average grant date fair value of the stock grants was $28.80, $30.14 and $22.98, in 2002, 2001 and 2000, respectively. Nonemployee directors may receive shares of common stock instead of cash in payment for director's fees under the nonemployee director stock compensation plan. Compensation expense recognized for restricted stock grants and stock grants was $5.2 million, $4.9 million and $1.8 million in 2002, 2001 and 2000, respectively. The Company is authorized to grant options, restricted stock and stock for up to 10.0 million shares of common stock and has granted options, restricted stock and stock on 4.7 million shares through December 31, 2002.

For a discussion of the effect on earnings and earnings per common share for the years ended December 31, 2002, 2001 and 2000, if the Company had applied SFAS No. 123, see Note 1.

A summary of the status of the stock option plans at December 31, 2002, 2001 and 2000, and changes during the years then ended was as follows:

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	2002 Shares	2002 Weighted Average Exercise Price	2001 Shares	2001 Weighted Average Exercise Price	2000 Shares	2000 Weighted Average Exercise Price
Balance at beginning of year	3,472,207	$27.90	1,224,959	$20.61	1,427,262	$19.46
Granted	107,070	28.72	2,693,120	30.14	74,000	20.54
Forfeited	(302,560)	29.66	(74,282)	27.24	(84,135)	21.18
Exercised	(35,872)	18.30	(371,590)	20.23	(192,168)	11.84
Balance at end of year	3,240,845	27.87	3,472,207	27.90	1,224,959	20.61
Exercisable at end of year	756,700	$21.84	770,142	$21.41	129,763	$18.11

Summarized information about stock options outstanding and exercisable as of December 31, 2002, was as follows:

	Options Outstanding			Options Exercisable	
Range of Exercisable Prices	Number Outstanding	Remaining Contractual Life in Years	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$12.33 - 17.50	28,374	2.9	$13.62	28,374	$13.62
17.51 - 24.50	762,521	5.3	21.14	671,326	21.14
24.51 - 31.50	2,301,910	8.2	29.69	27,000	29.32
31.51 - 38.55	148,040	8.2	36.87	30,000	38.55
Balance at end of year	3,240,845	7.4	27.87	756,700	21.84

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of the options granted and the assumptions used to estimate the fair value of options were as follows:

	2002	2001	2000
Weighted average fair value of options at grant date	$ 8.07	$ 7.38	$ 5.07
Weighted average risk-free interest rate	5.14%	5.19%	6.76%
Weighted average expected price volatility	30.80%	26.05%	23.55%
Weighted average expected dividend yield	3.43%	3.53%	3.84%
Expected life in years	7	7	7

NOTE 11

Income Taxes

Income tax expense for the years ended December 31 was as follows:

	2002	2001 (In thousands)	2000
Current:			
Federal	$ 46,389	$ 66,211	$ 27,865
State	9,082	11,160	5,188
Foreign	---	(44)	67
	55,471	77,327	33,120
Deferred:			
Income taxes --			
Federal	26,373	16,972	29,323

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State	4,632	4,773	8,060
Foreign	338	---	---
Investment tax credit	(584)	(731)	(853)
	30,759	21,014	36,530
Total income tax expense	$ 86,230	$ 98,341	$ 69,650

Components of deferred tax assets and deferred tax liabilities recognized at December 31 were as follows:

	2002	2001
	(In thousands)	
Deferred tax assets:		
Accrued pension costs	$ 12,112	$ 9,349
Regulatory matters	11,644	21,000
Deferred compensation	3,991	2,386
Bad debts	2,798	1,774
Deferred investment tax credit	1,185	1,413
Accrued land reclamation	263	1,648
Other	20,848	17,531
Total deferred tax assets	52,841	55,101
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	331,694	302,103
Basis differences on natural gas and oil producing properties	70,464	61,684
Regulatory matters	5,491	5,661
Other	10,412	9,092
Total deferred tax liabilities	418,061	378,540
Net deferred income tax liability	$ (365,220)	$ (323,439)

As of December 31, 2002 and 2001, no valuation allowance has been recorded associated with the above deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2001, to December 31, 2002, to deferred income tax expense:

	2002
	(In thousands)
Net change in deferred income tax liability from the preceding table	$ 41,781
Deferred taxes associated with acquisitions	(17,217)
Deferred taxes associated with other comprehensive loss	7,227
Other	(1,032)
Deferred income tax expense for the period	$ 30,759

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference were as follows:

Years ended December 31,	2002 Amount	%	2001 Amount	%	2000 Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	$ 82,136	35.0	$ 88,966	35.0	$ 63,237	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	10,279	4.4	11,311	4.5	8,044	4.4

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Investment tax credit amortization	(584)	(.3)	(731)	(.3)	(853)	(.5)
Depletion allowance	(2,200)	(.9)	(1,820)	(.7)	(1,631)	(.9)
Other items	(3,401)	(1.5)	615	.2	853	.5
Total income tax expense	$ 86,230	36.7	$ 98,341	38.7	$ 69,650	38.5

The Company considers earnings from its foreign equity method investment in a natural gas-fired electric generation facility in Brazil to be reinvested indefinitely outside of the United States and, accordingly, no U.S. deferred income taxes are recorded with respect to such earnings. Should the earnings be remitted as dividends, the Company may be subject to additional U.S. taxes, net of allowable foreign tax credits.

NOTE 12
Business Segment Data
The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. Prior to the fourth quarter of 2002, the Company reported six business segments consisting of electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production and construction materials and mining. During the fourth quarter of 2002, the Company added an additional segment, independent power production, based on the significance of this segment's operations. Substantially all of the operations of the independent power production segment began in 2002, therefore financial information for years prior to 2002 has not been presented.

The Company's operations are now conducted through seven business segments. The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which consists largely of an investment in a natural gas-fired electric generation station in Brazil as discussed in Note 2. The electric segment generates, transmits and distributes electricity and the natural gas distribution segment distributes natural gas. These operations also supply related value-added products and services in the northern Great Plains. The utility services segment consists of a diversified infrastructure company specializing in electric, gas and telecommunication utility construction, as well as industrial and commercial electrical, exterior lighting and traffic signalization throughout most of the United States. Utility services also provides related specialty equipment manufacturing, sales and rental services. The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. The pipeline and energy services segment also provides energy-related management services, including cable and pipeline magnetization and locating. The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration and production activities primarily in the Rocky Mountain region of the United States and in the Gulf of Mexico. The construction materials and mining segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt and other value-added products, as well as performing integrated construction services, in the north central and western United States, including Alaska and Hawaii. The independent power production segment owns electric generating facilities in the United States and Brazil. Electric capacity and energy produced at these facilities is sold under long-term contracts to nonaffiliated entities. This segment also invests in potential new growth and synergistic opportunities that are not directly being pursued by other business segments.

In 2001, the Company sold its coal operations to Westmoreland Coal Company for $28.2 million in cash, including final settlement cost adjustments. The sale of the coal operations was effective April 30, 2001. Included in the sale were active coal mines in North Dakota and Montana, coal sales agreements, reserves and mining equipment, and

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certain development rights at the former Gascoyne Mine site in North Dakota. The Company retains ownership of coal reserves and leases at its former Gascoyne Mine site. Including final settlement cost adjustments, the Company recorded a gain of $10.3 million ($6.2 million after tax) included in other income - net from the sale in 2001.

Segment information follows the same accounting policies as described in the Summary of Significant Accounting Policies. Segment information as of December 31 and for the years then ended was as follows:

	2002	2001 (In thousands)	2000
External operating revenues:			
Electric	$ 162,616	$ 168,837	$ 161,621
Natural gas distribution	186,569	255,389	233,051
Utility services	458,660	364,746	169,382
Pipeline and energy services	110,224	479,108	579,207
Natural gas and oil production	148,158	148,653	99,014
Construction materials and mining	962,312	801,883	617,564
Independent power production	2,998	---	---
Total external operating revenues	$ 2,031,537	$ 2,218,616	$ 1,859,839
Intersegment operating revenues:			
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Utility services	---	4	---
Pipeline and energy services	55,034	52,006	57,641
Natural gas and oil production	55,437	61,178	39,302
Construction materials and mining	---	5,016(a)	13,832(a)
Independent power production	3,778	---	---
Intersegment eliminations	(114,249)	(113,188)	(96,943)
Total intersegment operating revenues	$ ---	$ 5,016(a)	$ 13,832(a)
Depreciation, depletion and amortization:			
Electric	$ 19,537	$ 19,488	$ 19,115
Natural gas distribution	9,940	9,337	8,399
Utility services	9,871	8,395	4,912
Pipeline and energy services	14,846	14,341	15,301
Natural gas and oil production	48,714	41,690	27,008
Construction materials and mining	54,334	46,666	36,153
Independent power production	719	---	---
Total depreciation, depletion and amortization	$ 157,961	$ 139,917	$ 110,888
Interest expense:			
Electric	$ 7,621	$ 8,531	$ 10,007
Natural gas distribution	4,364	3,727	4,142
Utility services	3,568	3,807	2,492
Pipeline and energy services	7,670	9,136	10,029
Natural gas and oil production	2,464	1,359	5,160
Construction materials and mining	18,422	19,339	16,415
Independent power production	1,122	---	---
Intersegment eliminations	(216)	---	(212)
Total interest expense	$ 45,015	$ 45,899	$ 48,033
Income taxes:			
Electric	$ 9,501	$ 10,511	$ 10,048

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Natural gas distribution	(1,325)	1,067	3,544
Utility services	4,781	9,131	6,027
Pipeline and energy services	12,462	11,633	9,214
Natural gas and oil production	30,604	40,486	23,906
Construction materials and mining	29,415	25,513	16,911
Independent power production	792	---	---
Total income taxes	$ 86,230	$ 98,341	$ 69,650
Earnings on common stock:			
Electric	$ 15,780	$ 18,717	$ 17,733
Natural gas distribution	3,587	677	4,741
Utility services	6,371	12,910	8,607
Pipeline and energy services	19,097	16,406	10,494
Natural gas and oil production	53,192	63,178	38,574
Construction materials and mining	48,702	43,199	30,113
Independent power production	959	---	---
Total earnings on common stock	$ 147,688	$ 155,087	$ 110,262
Capital expenditures:			
Electric	$ 27,795	$ 14,373	$ 15,788
Natural gas distribution	11,044	14,685	21,336
Utility services	17,242	70,232	42,633
Pipeline and energy services	21,449	51,054	69,006
Natural gas and oil production	136,424	118,719	173,441
Construction materials and mining	106,893	170,585	218,716
Independent power production	95,748	---	---
Net proceeds from sale or disposition of property	(16,217)	(51,641)	(11,000)
Total net capital expenditures	$ 400,378	$ 388,007	$ 529,920
Identifiable assets:			
Electric(b)	$ 310,519	$ 291,229	$ 305,099
Natural gas distribution(b)	170,672	182,705	192,854
Utility services	230,888	239,069	123,451
Pipeline and energy services	302,972	346,879	362,592
Natural gas and oil production	554,420	476,105	410,207
Construction materials and mining	1,137,697	1,035,929	874,299
Independent power production	148,770	---	---
Corporate assets(c)	81,311	51,155	44,457
Total identifiable assets	$ 2,937,249	$ 2,623,071	$ 2,312,959
Property, plant and equipment:			
Electric (b)	$ 619,230	$ 597,080	$ 589,700
Natural gas distribution (b)	246,844	238,566	227,742
Utility services	70,660	59,190	39,865
Pipeline and energy services	412,694	410,049	369,834
Natural gas and oil production	755,788	630,826	513,419
Construction materials and mining	804,255	711,410	653,189
Independent power production	94,525	---	---
Less accumulated depreciation, depletion and amortization	1,079,110	942,723	891,228
Net property, plant and equipment	$ 1,924,886	$ 1,704,398	$ 1,502,521

(a) In accordance with the provision of SFAS No. 71, intercompany coal sales were not eliminated.

(b) Includes, in the case of electric and natural gas distribution property, allocations of common utility property.

(c) Corporate assets consist of assets not directly assignable to a business segment

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(i.e., cash and cash equivalents, certain accounts receivable and other miscellaneous current and deferred assets).

Capital expenditures for 2002, 2001 and 2000, related to acquisitions, in the preceding table included the following noncash transactions: issuance of the Company's equity securities of $47.2 million in 2002; issuance of the Company's equity securities of $57.4 million in 2001; and issuance of the Company's equity securities and the conversion of a note receivable to purchase consideration of $132.1 million in 2000.

NOTE 13
Acquisitions
In 2002, the Company acquired a number of businesses, none of which was individually material, including utility services companies in California and Ohio, construction materials and mining businesses in Minnesota and Montana, an energy development company in Montana and natural gas-fired electric generating facilities in Colorado. The total purchase consideration for these businesses, consisting of the Company's common stock and cash, was $139.8 million.

In 2001, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Hawaii, Minnesota and Oregon; utility services businesses based in Missouri and Oregon; and an energy services company specializing in cable and pipeline locating and tracking systems. The total purchase consideration for these businesses, consisting of the Company's common stock and cash, was $170.1 million.

In 2000, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses with operations in Alaska, California, Montana and Oregon; a coalbed natural gas development operation based in Colorado with related oil and gas leases and properties in Montana and Wyoming; utility services businesses based in California, Colorado, Montana and Ohio; a natural gas distribution business serving southeastern North Dakota and western Minnesota; and an energy services company based in Texas. The total purchase consideration for these businesses, consisting of the Company's common stock, cash and the conversion of a note receivable to purchase consideration, was $286.0 million.

On April 1, 2000, Fidelity Exploration & Production Company (Fidelity), an indirect wholly owned subsidiary of the Company, purchased substantially all of the assets of Preston Reynolds & Co., Inc. (Preston), a coalbed natural gas development operation, as previously discussed. Pursuant to the asset purchase and sale agreement, Preston could, but was not obligated to purchase, acquire and own an undivided 25 percent working interest (Seller's Option Interest) in certain oil and gas leases or properties acquired and/or generated by Fidelity. Fidelity had the right, but not the obligation, to purchase Seller's Option Interest from Preston for an amount as specified in the agreement. On July 10, 2002, Fidelity purchased the Seller's Option Interest.

The above acquisitions were accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed have been preliminarily recorded at their respective fair values as of the date of acquisition. Final fair market values are pending the completion of the review of the relevant assets, liabilities and issues identified as of the acquisition date on certain of the above acquisitions made in 2002. The results of operations of the acquired businesses are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the above acquisitions are not presented as such acquisitions were not material to the Company's financial position or results of operations.

NOTE 14
Employee Benefit Plans

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The Company has noncontributory defined benefit pension plans and other postretirement benefit plans. Changes in benefit obligation and plan assets for the years ended December 31 and amounts recognized in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$204,046	$200,880	$ 67,019	$ 69,467
Service cost	5,135	4,716	1,460	1,376
Interest cost	14,877	14,498	4,915	4,691
Plan participants' contributions	---	---	834	866
Amendments	372	(1,342)	---	---
Actuarial (gain) loss	12,324	8,128	5,678	(2,109)
Divestiture*	---	(10,017)	---	(2,871)
Benefits paid	(11,988)	(12,817)	(4,989)	(4,401)
Benefit obligation at end of year	224,766	204,046	74,917	67,019
Change in plan assets:				
Fair value of plan assets at beginning of year	224,667	261,864	45,175	47,046
Actual loss on plan assets	(26,543)	(13,828)	(4,196)	(2,235)
Employer contribution	3,007	337	4,065	3,899
Plan participants' contributions	---	---	834	866
Divestiture*	---	(10,889)	---	---
Benefits paid	(11,988)	(12,817)	(4,989)	(4,401)
Fair value of plan assets at end of year	189,143	224,667	40,889	45,175
Funded status - over (under)	(35,623)	20,621	(34,028)	(21,844)
Unrecognized actuarial (gain) loss	35,662	(26,170)	3,484	(10,799)
Unrecognized prior service cost	9,501	10,278	---	---
Unrecognized net transition obligation (asset)	(1,247)	(2,195)	21,513	23,665
Prepaid (accrued) benefit cost	8,293	2,534	(9,031)	(8,978)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid benefit cost	16,175	11,867	---	---
Accrued benefit liability	(7,882)	(9,333)	(9,031)	(8,978)
Additional minimum liability	(4,905)	---	---	---
Intangible asset	533	---	---	---
Accumulated other comprehensive loss	4,372	---	---	---
Net amount recognized	$ 8,293	$ 2,534	$ (9,031)	$ (8,978)

* See Note 12 for more information on the sale of the Company's coal operations.

Weighted average assumptions for the Company's pension and other postretirement benefit plans as of December 31 were as follows:

	Pension Benefits	Other Postretirement Benefits

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	2002	2001	2002	2001
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on plan assets	8.50%	8.50%	7.50%	7.50%
Rate of compensation increase	4.50%	5.00%	4.50%	5.00%

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2002	2001
Health care trend rate	6.00%-11.00%	6.00%-11.00%
Health care cost trend rate - ultimate	5.00%-6.00%	5.00%-6.00%
Year in which ultimate trend rate achieved	1999-2011	1999-2010

Components of net periodic benefit expense (income) for the Company's pension and other postretirement benefit plans were as follows:

	Pension Benefits			Other Postretirement Benefits		
Years ended December 31,	2002	2001	2000	2002	2001	2000
	(In thousands)					
Components of net periodic benefit cost:						
Service cost	$ 5,135	$ 4,716	$ 4,561	$ 1,460	$ 1,376	$ 1,307
Interest cost	14,877	14,498	14,174	4,915	4,691	4,946
Expected return on assets	(21,110)	(20,672)	(19,927)	(3,843)	(3,619)	(3,267)
Amortization of prior service cost	1,148	1,247	1,047	---	---	---
Recognized net actuarial gain	(1,855)	(2,687)	(2,907)	(566)	(930)	(799)
Settlement (gain) loss	---	(884)	(700)	---	15	---
Amortization of net transition obligation (asset)	(947)	(965)	(997)	2,151	2,227	2,378
Net periodic benefit cost (income)	(2,752)	(4,747)	(4,749)	4,117	3,760	4,565
Less amount capitalized	(352)	(391)	(397)	404	329	369
Net periodic benefit expense (income)	$ (2,400)	$ (4,356)	$(4,352)	$ 3,713	$ 3,431	$ 4,196

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets, for the pension plans with accumulated benefit obligations in excess of plan assets, were $22.1 million, $19.6 million and $17.3 million, respectively, as of December 31, 2002. As a result of the accumulated benefit obligations exceeding the fair value of plan assets for these plans, an additional minimum liability of $4.9 million was recognized in 2002. The additional minimum liability also reflects the amount of prepaid benefit cost or accrued benefit liability related to these plans.

The Company's other postretirement benefit plans include health care and life insurance benefits for certain employees. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have the following effects at December 31, 2002:

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	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 232	$ (841)
Effect on postretirement benefit obligation	$ 3,062	$ (8,076)

In addition to company-sponsored plans, certain employees are covered under multi-employer defined benefit plans administered by a union. Amounts contributed to the multi-employer plans were $27.8 million, $19.9 million and $10.6 million in 2002, 2001 and 2000, respectively.

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this footnote, the Company also has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that provides for defined benefit payments upon the employee's retirement or to their beneficiaries upon death for a 15-year period or as an equivalent life annuity. Investments consist of life insurance carried on plan participants, which is payable to the Company upon the employee's death. The cost of these benefits was $5.1 million, $4.3 million and $3.5 million in 2002, 2001 and 2000, respectively. The total projected obligation for this plan was $40.5 million and $41.0 million at December 31, 2002 and 2001, respectively. The additional minimum liability relating to this plan was $4.0 million at December 31, 2002. The Company has a related intangible asset recognized as of December 31, 2002, of $1.1 million. The actuarial valuations for this plan were determined based on a discount rate of 6.75 percent and 7.25 percent as of December 31, 2002 and 2001, respectively, and a rate of compensation increase of 4.50 percent and 5.00 percent as of December 31, 2002 and 2001, respectively.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $9.6 million in 2002, $7.2 million in 2001 and $6.1 million in 2000. The costs incurred in each year reflect additional participants as a result of business acquisitions.

NOTE 15
Jointly Owned Facilities
The consolidated financial statements include the Company's 22.7 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station and the Coyote Station, respectively. Each owner of the Big Stone and Coyote stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the Big Stone Station and Coyote Station operating expenses was reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2002	2001
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 53,018	$ 50,053
Less accumulated depreciation	34,456	32,956
	$ 18,562	$ 17,097
Coyote Station:		
Utility plant in service	$ 122,476	$ 122,436
Less accumulated depreciation	70,778	67,414
	$ 51,698	$ 55,022

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NOTES TO FINANCIAL STATEMENTS (Continued)

NOTE 16
Regulatory Matters and Revenues Subject To Refund
On December 30, 2002, Montana-Dakota Utilities Co. (Montana-Dakota), a public utility division of MDU Resources, filed an application with the South Dakota Public Utilities Commission (SDPUC) for a natural gas rate increase. Montana-Dakota requested a total of $2.2 million annually or 5.8 percent above current rates. A final order from the SDPUC is due June 30, 2003.

On October 7, 2002, Great Plains Natural Gas Co. (Great Plains), a public utility division of MDU Resources, filed an application with the Minnesota Public Utilities Commission (MPUC) for a natural gas rate increase. Great Plains requested a total of $1.6 million annually or 6.9 percent above current rates. On December 4, 2002, the MPUC issued an Order setting interim rates that approved an interim increase of $1.4 million annually effective December 6, 2002. Great Plains began collecting such rates effective December 6, 2002, subject to refund until the MPUC issues a final order. A final order from the MPUC is due August 22, 2003.

On June 10, 2002, Montana-Dakota filed an application with the Wyoming Public Service Commission (WYPSC) for a natural gas rate increase. Montana-Dakota requested a total of $662,000 annually or 5.6 percent above current rates. On December 9, 2002, the WYPSC approved an increase of $466,000 annually effective January 1, 2003.

On May 20, 2002, Montana-Dakota filed an application with the Montana Public Service Commission (MTPSC) for a natural gas rate increase. Montana-Dakota requested a total of $3.6 million annually or 6.5 percent above current rates. On September 5, 2002, the MTPSC approved an interim increase of $2.1 million annually, effective with service rendered on and after September 5, 2002. Montana-Dakota began collecting such rates effective September 5, 2002, which are subject to refund until the MTPSC issues a final order. On November 7, 2002, the MTPSC approved an additional interim increase of $300,000 annually effective November 15, 2002. The additional interim increase is the result of a Stipulation reached between Montana-Dakota and the Montana Consumer Counsel, the only intervener in the proceeding. Under the terms of the Stipulation, the total interim relief granted ($2.4 million) will be the final increase in the proceeding. A hearing before the MTPSC was held on December 6, 2002, at which the MTPSC took under advisement the Stipulation agreed upon by Montana-Dakota and the Montana Consumer Counsel. A final order from the MTPSC is due February 20, 2003.

On April 12, 2002, Montana-Dakota filed an application with the North Dakota Public Service Commission (NDPSC) for a natural gas rate increase. Montana-Dakota requested a total of $2.8 million annually or 4.1 percent above current rates. On December 10, 2002, the NDPSC approved an increase of $2.0 million annually, effective with service rendered on or after December 12, 2002.

Reserves have been provided for a portion of the revenues that have been collected subject to refund for certain of the above proceedings. The Company believes that such reserves are adequate based on its assessment of the ultimate outcome of the proceedings.

The NDPSC authorized its Staff to initiate an investigation into the earnings levels of Montana-Dakota's North Dakota electric operations based on Montana-Dakota's 2000 Annual Report to the NDPSC. The investigation was based on a complaint filed with the NDPSC in September 2001, by the NDPSC Staff. On April 24, 2002, the NDPSC issued an Order requiring Montana-Dakota to reduce its North Dakota electric rates by $4.3 million annually, effective May 8, 2002. On April 25, 2002, Montana-Dakota filed an appeal of the NDPSC Order in the North Dakota South Central Judicial District Court (District Court). The filing also requested a stay of the effectiveness of the NDPSC Order while the appeal was pending. Montana-Dakota challenged the NDPSC's determination of the level of

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NOTES TO FINANCIAL STATEMENTS (Continued)

wholesale electricity sales margins expected to be received by Montana-Dakota. On May 2, 2002, the District Court granted Montana-Dakota's request for a stay of a portion of the $4.3 million annual rate reduction ordered by the NDPSC. Accordingly, Montana-Dakota implemented an annual rate reduction of $800,000 effective with service rendered on and after May 8, 2002, rather than the $4.3 million annual reduction ordered by the NDPSC. The remaining $3.5 million was subject to refund if Montana-Dakota did not prevail in this proceeding. On November 22, 2002, the District Court issued an Order reversing the decision of the NDPSC and remanded the case back to the NDPSC. On January 15, 2003, the NDPSC issued an Order accepting Montana-Dakota's level of wholesale electricity sales margins thus reversing its initial decision and allowing Montana-Dakota to continue to charge the electric rates which were in effect.

Montana-Dakota had established reserves for 2002 revenues that had been collected subject to refund with respect to Montana-Dakota's pending electric rate reduction. Based on the January 15, 2003, Order, as previously discussed, the reserves were reversed and recognized in income in 2002.

In December 1999, Williston Basin filed a general natural gas rate change application with the FERC. Williston Basin began collecting such rates effective June 1, 2000, subject to refund. In May 2001, the Administrative Law Judge issued an Initial Decision on Williston Basin's natural gas rate change application. This matter is currently pending before and subject to revision by the FERC.

Reserves have been provided for a portion of the revenues that have been collected subject to refund with respect to Williston Basin's pending regulatory proceeding. Williston Basin, in the fourth quarter of 2000, determined that reserves it had previously established for certain regulatory proceedings, prior to the proceeding filed in 1999, exceeded its expected refund obligation and, accordingly, reversed reserves and recognized in income $6.7 million after tax. Williston Basin believes that its remaining reserves are adequate based on its assessment of the ultimate outcome of the application filed in December 1999.

NOTE 17
Commitments and Contingencies
Litigation
In January 2002, Fidelity Oil Co. (FOC), one of the Company's natural gas and oil production subsidiaries, entered into a compromise agreement with the former operator of certain of FOC's oil production properties in southeastern Montana. The compromise agreement resolved litigation involving the interpretation and application of contractual provisions regarding net proceeds interests paid by the former operator to FOC for a number of years prior to 1998. The terms of the compromise agreement are confidential. As a result of the compromise agreement, the natural gas and oil production segment reflected a nonrecurring gain in its financial results for the first quarter of 2002 of approximately $16.6 million after tax. As part of the settlement, FOC gave the former operator a full and complete release, and FOC is not asserting any such claim against the former operator for periods after 1997.

In July 1996, Jack J. Grynberg (Grynberg) filed suit in United States District Court for the District of Columbia (U.S. District Court) against Williston Basin and over 70 other natural gas pipeline companies. Grynberg, acting on behalf of the United States under the Federal False Claims Act, alleged improper measurement of the heating content and volume of natural gas purchased by the defendants resulting in the underpayment of royalties to the United States. In March 1997, the U.S. District Court dismissed the suit without prejudice and the dismissal was affirmed by the United States Court of Appeals for the D.C. Circuit in October 1998. In June 1997, Grynberg filed a similar Federal False Claims Act suit against Williston Basin and Montana-Dakota and filed over 70 other separate similar suits against natural gas transmission companies and producers, gatherers, and processors of natural gas. In April 1999, the United States Department of Justice decided not to intervene in these cases. In response to a motion filed by Grynberg, the Judicial Panel on Multidistrict Litigation consolidated all of these cases in the Federal District Court of Wyoming (Federal District Court). Oral argument on motions to dismiss was held before the Federal District Court in March 2000. In May 2001, the Federal District Court denied Williston Basin's and Montana-Dakota's motion to dismiss. The matter is currently pending.

The Quinque Operating Company (Quinque), on behalf of itself and subclasses of gas producers, royalty owners and state taxing authorities, instituted a legal proceeding in State District Court for Stevens County, Kansas, (State District Court) against over 200 natural gas transmission companies and producers, gatherers, and processors of natural gas, including Williston Basin and Montana-Dakota. The complaint, which was served on Williston Basin and Montana-Dakota in September 1999, contains allegations of improper measurement of the heating content and volume of all natural gas measured by the defendants other than natural gas produced from federal lands. In response to a motion filed by the defendants in this suit, the Judicial Panel on Multidistrict Litigation transferred the suit to the Federal District Court for inclusion in the pretrial proceedings of the Grynberg suit. Upon motion of plaintiffs, the case has been remanded to State District Court. In September 2001, the defendants in this suit filed a motion to dismiss with the State District Court. The motion to dismiss was denied by the State District Court on August 19, 2002. The matter is currently pending.

Williston Basin and Montana-Dakota believe the claims of Grynberg and Quinque are without merit and intend to vigorously contest these suits. Williston Basin and Montana-Dakota believe it is not probable that Grynberg and Quinque will ultimately succeed given the current status of the litigation.

The Company is also involved in other legal actions in the ordinary course of its business. Although the outcomes of any such legal actions cannot be predicted, management believes that the outcomes with respect to these other legal proceedings will not have a material adverse effect upon the Company's financial position or results of operations.

Environmental matters

In December 2000, Morse Bros., Inc. (MBI), an indirect wholly owned subsidiary of the Company, was named by the United States Environmental Protection Agency (EPA) as a Potentially Responsible Party in connection with the cleanup of a commercial property site, now owned by MBI, and part of the Portland, Oregon, Harbor Superfund Site. Sixty-eight other parties were also named in this administrative action. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon State Department of Environmental Quality and other information available, MBI does not believe it is a Responsible Party. In addition, MBI intends to seek indemnity for any and all liabilities incurred in relation to the above matters from Georgia-Pacific West, Inc., the seller of the commercial property site to MBI, pursuant to the terms of their sale agreement.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above administrative action.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2002, were $19.3 million in 2003, $14.3 million in 2004, $11.2 million in 2005, $7.8 million in 2006, $4.3 million in 2007 and $21.3 million thereafter. Rent expense related to operating leases was approximately $26.9 million, $31.5 million and $23.7 million for the years ended December 31, 2002, 2001 and 2000, respectively.

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Purchase commitments
The Company has entered into various commitments, largely purchased power, coal and natural gas supply, electric generation construction and natural gas transportation contracts. These commitments range from one to 18 years. The commitments under these contracts as of December 31, 2002, were $171.3 million in 2003, $55.4 million in 2004, $43.1 million in 2005, $37.0 million in 2006, $27.6 million in 2007 and $130.4 million thereafter. These commitments are not reflected in the Company's consolidated financial statements.

Guarantees
Centennial has guaranteed, with the right of subrogation, a portion of certain obligations of MPX in connection with the Company's equity method investment in the natural gas-fired electric generation station in Brazil, as discussed in Note 2. The Company, through a subsidiary, owns 49 percent of MPX. These guarantees expire in 2003, and at December 31, 2002, the maximum amounts outstanding under these guarantees totaled $24.9 million. In the event MPX defaults under its obligations, Centennial would be required to make payments under these guarantees. These guarantees are not reflected on the Consolidated Balance Sheets.

In addition, Centennial has guaranteed, without recourse, the short-term line of credit agreement of a subsidiary of the Company as discussed in Note 7. The proceeds from the short-term line of credit were used in connection with the Company's investment in international projects. The fixed maximum amount of Centennial's guarantee of this line of credit is $25 million and the amount outstanding under this line of credit at December 31, 2002, was $12.0 million, which amount is reflected on the Consolidated Balance Sheets. This subsidiary of the Company intends to renew this credit agreement, which expires June 30, 2003. In the event this subsidiary of the Company defaults under its obligation, Centennial would be required to make payments under its guarantee.

Centennial has guaranteed, without recourse, a foreign currency collar agreement obligation of an indirect wholly owned subsidiary of the Company. There is no fixed maximum amount guaranteed under the foreign currency collar agreement. The Company recorded an asset for the fair value of the foreign currency collar agreement at December 31, 2002, of $903,000, therefore there was no outstanding obligation guaranteed at December 31, 2002. The foreign currency collar agreement expires on February 3, 2003. In addition, WBI Holdings, Inc. (WBI Holdings), an indirect wholly owned subsidiary of the Company, has guaranteed, without recourse, certain of its subsidiary's natural gas and oil price swap and collar agreement obligations. The amount of the subsidiary's obligation at December 31, 2002, was $4.2 million. There is no fixed maximum amount guaranteed in relation to the natural gas and oil price swap and collar agreements; however, the amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil price swap and collar agreements expire in December 2003; however, WBI Holdings anticipates continued hedging activities by its subsidiary, and, as a result, will likely issue additional guarantees on potential hedging obligations. The amounts outstanding under the natural gas and oil price swap and collar agreements were reflected on the Consolidated Balance Sheets. In the event the above subsidiaries default under their obligations, Centennial and WBI Holdings would be required to make payments under their respective guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company that are related to natural gas transportation and sales agreements, electric power supply agreements and certain other guarantees. These guarantees are without recourse and at December 31, 2002, the fixed maximum amounts guaranteed under these agreements aggregated $55.8 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $29.0 million in 2003; $1.4 million in 2004; $20.0 million in 2009; $2.0

million, which is subject to expiration 30 days after the receipt of written notice; $425,000, which expires upon completion of a guaranteed project and $3.0 million, which has no scheduled maturity date. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantees. Any amounts outstanding by subsidiaries of the Company under the above guarantees were reflected on the Consolidated Balance Sheets at December 31, 2002.

In addition, Centennial has issued guarantees related to the Company's purchase of maintenance items to third parties for which no fixed maximum amounts have been specified. These guarantees are without recourse and have no scheduled maturity date. In the event a subsidiary of the Company defaults under its obligation in relation to the purchase of certain maintenance items, Centennial would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for maintenance were reflected on the Consolidated Balance Sheets at December 31, 2002.

As of December 31, 2002, Centennial was contingently liable for performance of certain of its subsidiaries under approximately $200 million of surety bonds. These bonds are principally for construction contracts and reclamation obligations of these subsidiaries, entered into in the normal course of business. Centennial indemnifies the respective surety bond companies against any exposure under the bonds. A large portion of these contingent commitments expire in 2003, however Centennial will likely continue to enter into surety bonds for its subsidiaries in the future.

Centennial has also guaranteed a wholly owned subsidiary's payment to a third party of the $102.5 million acquisition price in connection with the acquisition of the 66.6-megawatt wind-powered electric generation facility in California. The guarantee will terminate upon the occurrence of the closing of the purchase of the above facility and is without recourse. For more information on the purchase of this facility, see Note 19.

NOTE 18
Inability to Obtain Consent of Prior Independent Public Accountants
There may be risks and stockholders' recovery may be limited as a result of the Company's prior use of Arthur Andersen LLP as the Company's independent public accounting firm. On June 15, 2002, Arthur Andersen LLP was convicted for obstruction of justice charges. Arthur Andersen LLP audited the Company's financial statements for the years ended December 31, 2001 and 2000. On February 14, 2002, Arthur Andersen LLP was dismissed as the Company's independent public accountants and on March 25, 2002, Deloitte & Touche LLP was hired as the Company's independent auditors for the 2002 fiscal year. Because the former audit partner and manager have left Arthur Andersen LLP, the Company was not able to obtain the written consent of Arthur Andersen LLP as required by Section 7 of the Securities Act of 1933 (the Securities Act). Accordingly, investors will not be able to sue Arthur Andersen LLP pursuant to Section 11(a)(4) of the Securities Act and therefore may have their recovery limited as a result of the lack of consent.

NOTE 19
Subsequent Event
On January 31, 2003, Centennial Power, Inc., an indirect wholly owned subsidiary of the Company, purchased a 66.6-megawatt wind-powered electric generation facility from San Gorgonio Power Corporation, an affiliate of PG&E National Energy Group, for $102.5 million cash, subject to certain closing adjustments. This facility is located in the San Gorgonio Pass, northwest of Palm Springs, California. The facility consists of 111 wind turbines and began commercial operation in September 2001. The facility sells all of its output under a long-term contract with the California Department of Water Resources. SeaWest Wind Power, Inc. will continue to operate the facility.

NOTE 20

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Investment in Subsidiaries

The Respondent owns two wholly owned subsidiaries, Centennial Energy Holdings, Inc. and MDU Resources International, Inc.

As required by the Federal Energy Regulatory Commission for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investment using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiary, as required by generally accepted accounting principles. If generally accepted accounting principles were followed, utility plant, other property and investments would increase by $440,603,661 and $501,669,316; current and accrued assets would increase by $429,117,903 and $376,353,971; deferred debits would increase by $382,761,205 and $276,502,929; preferred stock would decrease by $100,000 and $100,000; long-term debt would increase by $636,749,515 and $625,404,164; other noncurrent liabilities and current and accrued liabilities would increase by $208,485,102 and $157,590,276; deferred credits would increase by $410,973,964 and $373,039,122 as of December 31, 2002 and 2001, respectively. Furthermore, operating revenues would increase by $1,682,352,992 and $1,799,405,574; and operating expenses, excluding income taxes, would increase by $1,452,565,545 and $1,568,444,117 for the year ended December 31, 2002 and 2001, respectively. In addition, net cash provided by operating activities would increase by $298,919,000; net cash used in investing activities would increase by $270,655,000; net cash provided by financing activities would decrease by $6,853; and the net change in cash and cash equivalents would be an increase of $21,411,000 for the year ended December 31, 2002. Reporting its subsidiary investment using the equity method rather than generally accepted accounting principles has no effect on net income or retained earnings.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2002

Account Number & Title		Last Year	This Year	% Change
Intangible Plant				
301	Organization			
302	Franchises & Consents			
303	Miscellaneous Intangible Plant	$1,525,858	$1,704,082	11.68%
TOTAL Intangible Plant		$1,525,858	$1,704,082	11.68%
Production Plant				
Production & Gathering Plant				
325.1	Producing Lands			
325.2	Producing Leaseholds			
325.3	Gas Rights			
325.4	Rights-of-Way			
325.5	Other Land & Land Rights			
326	Gas Well Structures			
327	Field Compressor Station Structures			
328	Field Meas. & Reg. Station Structures			
329	Other Structures		NOT	
330	Producing Gas Wells-Well Construction		APPLICABLE	
331	Producing Gas Wells-Well Equipment			
332	Field Lines			
333	Field Compressor Station Equipment			
334	Field Meas. & Reg. Station Equipment			
335	Drilling & Cleaning Equipment			
336	Purification Equipment			
337	Other Equipment			
338	Unsuccessful Exploration & Dev. Costs			
Total Production & Gathering Plant				
Products Extraction Plant				
340	Land & Land Rights			
341	Structures & Improvements			
342	Extraction & Refining Equipment			
343	Pipe Lines		NOT	
344	Extracted Products Storage Equipment		APPLICABLE	
345	Compressor Equipment			
346	Gas Measuring & Regulating Equipment			
347	Other Equipment			
Total Products Extraction Plant				
TOTAL Production Plant				

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2002

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Natural Gas Storage and Processing Plant**			
3				
4	Underground Storage Plant			
5				
6	350.1 Land			
7	350.2 Rights-of-Way			
8	351 Structures & Improvements			
9	352 Wells			
10	352.1 Storage Leaseholds & Rights			
11	352.2 Reservoirs		NOT	
12	352.3 Non-Recoverable Natural Gas		APPLICABLE	
13	353 Lines			
14	354 Compressor Station Equipment			
15	355 Measuring & Regulating Equipment			
16	356 Purification Equipment			
17	357 Other Equipment			
18				
19	**Total Underground Storage Plant**			
20				
21	Other Storage Plant			
22				
23	360 Land & Land Rights			
24	361 Structures & Improvements			
25	362 Gas Holders			
26	363 Purification Equipment			
27	363.1 Liquification Equipment		NOT	
28	363.2 Vaporizing Equipment		APPLICABLE	
29	363.3 Compressor Equipment			
30	363.4 Measuring & Regulating Equipment			
31	363.5 Other Equipment			
32				
33	**Total Other Storage Plant**			
34				
35	**TOTAL Natural Gas Storage and Processing Plant**			
36				
37	**Transmission Plant**			
38				
39	365.1 Land & Land Rights			
40	365.2 Rights-of-Way			
41	366 Structures & Improvements			
42	367 Mains		NOT	
43	368 Compressor Station Equipment		APPLICABLE	
44	369 Measuring & Reg. Station Equipment			
45	370 Communication Equipment			
46	371 Other Equipment			
47				
48	**TOTAL Transmission Plant**			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2002

	Account Number & Title		Last Year	This Year	% Change
1					
2	**Distribution Plant**				
3					
4	374	Land & Land Rights	$34,899	$36,258	3.89%
5	375	Structures & Improvements	190,307	190,307	0.00%
6	376	Mains	20,952,392	21,336,324	1.83%
7	377	Compressor Station Equipment			
8	378	Meas. & Reg. Station Equipment-General	536,779	540,110	0.62%
9	379	Meas. & Reg. Station Equipment-City Gate	129,124	129,124	0.00%
10	380	Services	10,930,674	11,339,501	3.74%
11	381	Meters	10,041,174	10,560,808	5.18%
12	382	Meter Installations			
13	383	House Regulators	1,412,177	1,443,655	2.23%
14	384	House Regulator Installations			
15	385	Industrial Meas. & Reg. Station Equipment	112,646	114,152	1.34%
16	386	Other Prop. on Customers' Premises 1/	161,799	161,799	0.00%
17	387	Other Equipment	861,735	879,871	2.10%
18					
19	**TOTAL Distribution Plant**		$45,363,706	$46,731,909	3.02%
20					
21	**General Plant**				
22					
23	389	Land & Land Rights	$26,744	$26,745	0.00%
24	390	Structures & Improvements	299,252	434,374	45.15%
25	391	Office Furniture & Equipment	210,592	245,750	16.69%
26	392	Transportation Equipment	1,923,223	1,803,432	-6.23%
27	393	Stores Equipment	48,508	48,508	0.00%
28	394	Tools, Shop & Garage Equipment	919,305	943,718	2.66%
29	395	Laboratory Equipment	88,913	88,890	-0.03%
30	396	Power Operated Equipment	1,312,169	1,347,564	2.70%
31	397	Communication Equipment	354,424	348,651	-1.63%
32	398	Miscellaneous Equipment	43,357	43,363	0.01%
33	399	Other Tangible Property			
34					
35	**TOTAL General Plant**		$5,226,487	$5,330,995	2.00%
36					
37	**Common Plant**				
38					
39	389	Land & Land Rights	$167,937	$183,632	9.35%
40	390	Structures & Improvements	2,104,655	2,082,948	-1.03%
41	391	Office Furniture & Equipment	1,012,162	1,090,455	7.74%
42	392	Transportation Equipment	644,544	770,695	19.57%
43	393	Stores Equipment	9,287	9,360	0.79%
44	394	Tools, Shop & Garage Equipment	144,828	148,013	2.20%
45	396	Power Operated Equipment	13,626	12,013	-11.84%
46	397	Communication Equipment	508,293	553,108	8.82%
47	398	Miscellaneous Equipment	65,288	74,261	13.74%
48					
49	**TOTAL Common Plant**		$4,670,620	$4,924,485	5.44%
50					
51	**TOTAL Gas Plant in Service**		$56,786,671	$58,691,471	3.35%

1/ Includes gas plant leased to others.

MONTANA DEPRECIATION SUMMARY

Year: 2002

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1	Production & Gathering				
2	Products Extraction				
3	Underground Storage				
4	Other Storage				
5	Transmission				
6	Distribution	$46,731,909	$29,164,510	$30,831,068	3.98%
7	General	5,386,013	2,455,417	2,471,584	1.58%
8	Common	6,573,549	2,471,280	2,895,189	5.69%
9	**TOTAL**	$58,691,471	$34,091,207	$36,197,841	3.95%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock			
3	152 Fuel Stock Expenses - Undistributed			
4	153 Residuals & Extracted Products			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)			
9	Transmission Plant (Estimated)			
10	Distribution Plant (Estimated)	$339,713	$316,009	-6.98%
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	163 Stores Expense Undistributed			
15				
16	**TOTAL Materials & Supplies**	$339,713	$316,009	-6.98%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent 1/		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	D95.7.90			
2	Order Number	5856b			
3					
4	Common Equity		44.810%	12.000%	5.377%
5	Preferred Stock		1.810%	4.653%	0.084%
6	Long Term Debt		53.390%	10.212%	5.452%
7	Other				
8	**TOTAL**				10.913%
9					
10	Actual at Year End				
11					
12	Common Equity		51.229%	12.000%	6.147%
13	Preferred Stock		5.330%	4.624%	0.246%
14	Long Term Debt		43.441%	9.211%	4.001%
15	Other				
16	**TOTAL**		100.000%		10.394%

1/ Docket No. D2002.5.59, filed May 20, 2002, was settled pursuant to a Stipulation.
A capital structure and costs were not specifically stipulated.

STATEMENT OF CASH FLOWS

Year: 2002

	Description	Last Year	This Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2				
3	**Cash Flows from Operating Activities:**			
4	Net Income	$155,848,507	$148,443,958	-4.75%
5	Depreciation	28,824,072	29,476,227	2.26%
6	Amortization	1,434,400	1,340,106	-6.57%
7	Deferred Income Taxes - Net	(11,341,055)	7,430,927	-165.52%
8	Investment Tax Credit Adjustments - Net	(731,288)	(583,775)	-20.17%
9	Change in Operating Receivables - Net	25,805,961	(9,986,431)	-138.70%
10	Change in Materials, Supplies & Inventories - Net	(19,266,734)	9,697,089	150.33%
11	Change in Operating Payables & Accrued Liabilities - Net	(17,232,734)	(10,398,195)	39.66%
12	Change in Other Regulatory Assets	368,020	(181,217)	-149.24%
13	Change in Other Regulatory Liabilities	900,865	(760,117)	-184.38%
14	Allowance for Funds Used During Construction (AFUDC)	(185,066)	(132,880)	-28.20%
15	Change in Other Assets & Liabilities - Net	44,089,298	(18,612,724)	-142.22%
16	Less Undistributed Earnings from Subsidiary Companies	(135,692,353)	(128,320,376)	-5.43%
17	Other Operating Activities (explained on attached page)			
18	**Net Cash Provided by/(Used in) Operating Activities**	$72,821,893	$27,412,592	-62.36%
19				
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment			
22	(net of AFUDC & Capital Lease Related Acquisitions)	($30,174,257)	($36,510,374)	21.00%
23	Acquisition of Other Noncurrent Assets	(1,263,118)	(934,861)	-25.99%
24	Proceeds from Disposal of Noncurrent Assets			
25	Investments In and Advances to Affiliates	(130,138,498)	(96,870,417)	-25.56%
26	Contributions and Advances from Affiliates	39,709,000	51,045,000	28.55%
27	Disposition of Investments in and Advances to Affiliates			
28	Other Investing Activities: Depreciation & RWIP on Nonutility Plant	11,230	43,342	285.95%
29	**Net Cash Provided by/(Used in) Investing Activities**	($121,855,643)	($83,227,310)	-31.70%
30				
31	**Cash Flows from Financing Activities:**			
32	Proceeds from Issuance of:			
33	Long-Term Debt	$0	$25,000,000	100.00%
34	Preferred Stock			
35	Common Stock	132,499,140	96,035,929	-27.52%
36	Other:			
37	Net Increase in Short-Term Debt			
38	Other: Commercial Paper	0	8,000,000	100.00%
39	Payment for Retirement of:			
40	Long-Term Debt	(15,543,971)	(500,000)	-96.78%
41	Preferred Stock	(100,000)	(100,000)	0.00%
42	Common Stock			
43	Other:			
44	Net Decrease in Short-Term Debt	(8,000,000)	0	-100.00%
45	Dividends on Preferred Stock	(761,507)	(756,406)	-0.67%
46	Dividends on Common Stock	(61,094,016)	(67,530,664)	10.54%
47	Other Financing Activities (explained on attached page)			
48	**Net Cash Provided by (Used in) Financing Activities**	$46,999,646	$60,148,859	27.98%
49				
50	**Net Increase/(Decrease) in Cash and Cash Equivalents**	($2,034,104)	$4,334,141	-313.07%
51	**Cash and Cash Equivalents at Beginning of Year**	$7,088,695	$5,054,591	-28.70%
52	**Cash and Cash Equivalents at End of Year**	$5,054,591	$9,388,732	85.75%

LONG TERM DEBT

Year: 2002

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost % 1/
1	8.25 % Secured MTN, Series A	04/92	04/07	$30,000,000	$26,111,796	$30,000,000	8.25%	$3,053,100	10.18%
2	8.60 % Secured MTN, Series A	04/92	04/12	35,000,000	28,906,532	35,000,000	8.60%	3,857,000	11.02%
3	6.52 % Secured MTN, Series A	09/97	10/04	15,000,000	14,082,923	15,000,000	6.52%	1,171,650	7.81%
4	6.71 % Secured MTN, Series A	09/97	10/09	15,000,000	13,488,404	15,000,000	6.71%	1,229,250	8.20%
5	5.83 % Secured MTN, Series A	09/98	10/08	15,000,000	14,813,914	15,000,000	5.83%	912,900	6.09%
6	Grant County 6.20 % PCN	03/74	03/04	5,600,000	5,427,042	2,000,000	6.20%	131,120	6.56%
7	Mercer County 6.65 % 2/	06/92	06/22	15,000,000	14,061,276	15,000,000	6.65%	1,093,200	7.29%
8	Richland County 6.65 % 2/	06/92	06/22	3,250,000	3,063,677	3,250,000	6.65%	235,398	7.24%
9	Morton County 6.65 % 2/	06/92	06/22	2,600,000	2,420,986	2,600,000	6.65%	190,944	7.34%
10									
11									
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22									
23									
24									
25									
26	**TOTAL**			$136,450,000	$122,376,550	$132,850,000		$11,874,562	8.94%

1/ Includes interest expense, bond discount expense, debt issuance expense and loss on bond reacquistion and redemption.
2/ Pollution Control Refunding Revenue Bonds.

PREFERRED STOCK

Year: 2002

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price 1/	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	4.50 % Cumulative	01/51	100,000	$100	$105	$10,000,000	4.50%	$10,000,000	$450,000	4.50%
2	4.70 % Cumulative	12/55	50,000	100	102	5,000,000	4.70%	5,000,000	235,000	4.70%
3	5.10 % Cumulative	05/61	50,000	100	102	4,947,548	5.29%	1,300,000	68,705	5.29%
4										
5										
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27										
28										
29										
30										
31										
32	**TOTAL**					$19,947,548		$16,300,000	$753,705	4.62%

1/ Plus accrued dividends.

COMMON STOCK

Year: 2002

		Avg. Number of Shares Outstanding 1/	Book Value Per Share	Earnings Per Share 2/	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio 3/
1									
2									
3									
4	January								
5									
6	February								
7									
8	March	69,468,763	$16.08	$0.34	$0.23	32.35%	$31.09	$27.25	14.6 X
9									
10	April								
11									
12	May								
13									
14	June	70,455,821	16.30	0.35	0.23	34.29%	33.45	25.75	14.4 X
15									
16	July								
17									
18	August								
19									
20	September	70,923,411	16.80	0.76	0.24	68.42%	27.40	18.00	12.3 X
21									
22	October								
23									
24	November								
25									
26	December	72,094,704	17.34	0.63	0.24	61.90%	25.99	20.91	12.5 X
27									
28									
29									
30	TOTAL Year End	70,743,383	$17.34	$2.09	$0.94	55.02%			12.5 X

1/ Basic shares
2/ Basic earnings per share.
3/ Calculated on 12 months ended using closing stock price.

(Per agreement between Regulatory Affairs and Corporate Accounting, only quarter data is being presented.)

MONTANA EARNED RATE OF RETURN

Year: 2002

		Description	Last Year	This Year	% Change
		Rate Base			
1					
2	101	Plant in Service	$56,786,671	$58,691,471	3.35%
3	108	(Less) Accumulated Depreciation	34,091,207	36,197,841	6.18%
4					
5		**NET Plant in Service**	$22,695,464	$22,493,630	-0.89%
6					
7		CWIP in Service Pending Reclassification	$130,729	$210,403	60.95%
8					
9		Additions			
10	154, 156	Materials & Supplies	$339,713	$316,009	-6.98%
11	165	Prepayments	17,446	27,389	56.99%
12		Prepaid Demand/Commodity Charges	1,306,868	895,984	-31.44%
13		Gas in Underground Storage	8,690,912	5,193,643	-40.24%
14		Unamoritzed Gas IRP	125,416	89,708	-28.47%
15					
16		**TOTAL Additions**	$10,480,355	$6,522,733	-37.76%
17					
18		Deductions			
19	190	Accumulated Deferred Income Taxes	$3,338,641	$3,290,308	-1.45%
20	252	Customer Advances for Construction	176,934	329,770	86.38%
21	255	Accumulated Def. Investment Tax Credits	258,473	237,105	-8.27%
22		Other Deductions			
23					
24		**TOTAL Deductions**	$3,774,048	$3,857,183	2.20%
25		**TOTAL Rate Base**	$29,532,500	$25,369,583	-14.10%
26					
27		**Net Earnings**	$889,277	$2,867,100	222.41%
28					
29		**Rate of Return on Average Rate Base**	3.40%	10.44%	207.06%
30					
31		**Rate of Return on Average Equity**	-1.79%	12.09%	775.42%
32					
33		Major Normalizing Adjustments & Commission			
34		Ratemaking adjustments to Utility Operations 1/			
35					
36		Adjustment to Operating Revenues			
37		Weather Normalization	263,679	(37,704)	-114.30%
38		Late Payment Revenue	47,968	20,924	-56.38%
39					
40		Adjustment to Operating Expenses			
41		Elimination of Promotional & Institutional Advertising	(34,168)	(21,876)	-35.98%
42					
43		Total Adjustments to Operating Income	$345,815	$5,096	-98.53%
44					
45					
46		**Adjusted Rate of Return on Average Rate Base**	4.72%	10.46%	121.61%
47					
48		**Adjusted Rate of Return on Average Equity**	0.81%	12.13%	1397.53%

1/ Updated amounts, net of taxes.

MONTANA COMPOSITE STATISTICS

Year: 2002

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	$54,493
5	107	Construction Work in Progress	543
6	114	Plant Acquisition Adjustments	
7	104	Plant Leased to Others	13
8	105	Plant Held for Future Use	
9	154, 156	Materials & Supplies	316
10		(Less):	
11	108, 111	Depreciation & Amortization Reserves	36,198
12	252	Contributions in Aid of Construction	330
13			
14		**NET BOOK COSTS**	$18,837
15			
16		Revenues & Expenses (000 Omitted)	
17			
18	400	Operating Revenues	$48,030
19			
20	403 - 407	Depreciation & Amortization Expenses	$2,320
21		Federal & State Income Taxes	934
22		Other Taxes	1,903
23		Other Operating Expenses	40,006
24		TOTAL Operating Expenses	$45,163
25			
26		Net Operating Income	$2,867
27			
28		Other Income	567
29		Other Deductions	1,475
30			
31		**NET INCOME**	$1,959
32			
33		Customers (Intrastate Only)	
34			
35		Year End Average:	
36		Residential	62,947
37		Firm General	7,631
38		Small Interruptible	40
39		Large Interruptible	5
40			
41		**TOTAL NUMBER OF CUSTOMERS**	70,623
42			
43		Other Statistics (Intrastate Only)	
44			
45		Average Annual Residential Use (Dkt))	99
46		Average Annual Residential Cost per (Dkt) ($) * 1/	$5.52
		* Avg annual cost = [(cost per Dkt x annual use) +	
47		(mo. svc chrg x 12)]/annual use	
48		Average Residential Monthly Bill	$39.09
49		Gross Plant per Customer	$772

1/ Reflects cost per dk effective December 1, 2001.

MONTANA CUSTOMER INFORMATION

Year: 2002

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Belfry	219	135	20		155
2	Billings	89,847	39,596	3,784		43,380
3	Bridger	745	396	70		466
4	Crow Agency	1,552	320	63		383
5	Edgar	Not Available	102	8		110
6	Fromberg	486	274	22		296
7	Hardin	3,384	1,253	202		1,455
8	Joliet	575	340	42		382
9	Laurel	6,255	3,294	260		3,554
10	Park City	870	461	22		483
11	Pryor	628	83	12		95
12	Rockvale	Not Available	60	4		64
13	Silesia	Not Available	32	2		34
14	Warren	Not Available		1		1
15	Alzada	Not Available	7	6		13
16	Baker	1,695	766	168		934
17	Carlyle	Not Available	8	1		9
18	Fort Peck	240	126	9		135
19	Fairview	709	347	47		394
20	Forsyth	1,944	869	141		1,010
21	Frazer	452	94	14		108
22	Glasgow	3,253	1,647	297		1,944
23	Glendive	4,729	2,971	409		3,380
24	Hinsdale	Not Available	114	17		131
25	Ismay	26	8	4		12
26	Malta	2,120	998	198		1,196
27	Miles City	8,487	3,874	507		4,381
28	Nashua	325	183	20		203
29	Poplar	911	869	129		998
30	Richey	189	124	25		149
31	Rosebud	Not Available	45	5		50
32	Saco	224	42	7		49
33	Savage	Not Available	147	16		163
34	Sidney	4,774	2,240	387		2,627
35	Terry	611	314	61		375
36	St. Marie	183	136	10		146
37	Wibaux	567	216	51		267
38	Whitewater	Not Available	37	9		46
39	Wolf Point	2,663	1,408	202		1,610
40	MT Oil Fields	Not Available	2	3		5
41	**TOTAL Montana Customers**	138,663	63,938	7,255		71,193

1/ 2000 Census.

MONTANA EMPLOYEE COUNTS 1/

Year: 2002

	Department	Year Beginning	Year End	Average
1	Electric	20	20	20
2	Gas	43 (3)	41 (1)	42 (2)
3	Accounting	21 (1)	20	21
4	Marketing/Communications	5	5	5
5	Management	6	6	6
6	Power	26	26	26
7	Service 2/	59 (2)	56 (3)	57 (3)
8				
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40				
41				
42	**TOTAL Montana Employees**	180 (6)	174 (4)	177 (5)

1/ Parentheses denotes part-time.

2/ Reflects service employees such as meter readers and servicemen.

Company Name: Montana-Dakota Utilities Co. SCHEDULE 31

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2002

	Project Description	Total Company	Total Montana	
1	Projects>$1,000,000			
2				
3	Common-General			
4	Replace Conquest Aircraft	$4,620,150	$1,120,160	1/
5	Develop Geospacial Enterprise Management System	1,588,138	409,716	1/
6				
7	Electric-Other Production			
8	Construct Combustion Turbine-Glendive, MT	$10,999,553	$2,660,004	1/
9				
10				
11				
12	Other Projects<$1,000,000			
13				
14	Electric			
15	Production	$5,636,005	$1,362,897	1/
16	Transmission:			
17	Integrated	1,363,481	350,864	1/
18	Direct	595,245	132,857	2/
19	Distribution	6,802,410	927,052	2/
20	General	1,330,662	204,510	2/
21	Common:			
22	General Office	1,572,764	373,071	1/
23	Other Direct	604,464	90,207	2/
24	Total Electric	$17,905,031	$3,441,458	
25				
26	Gas			
27	Distribution	7,212,652	$2,377,441	1/
28	General	1,872,597	583,402	1/
29	Common:			2/
30	General Office	1,126,707	318,537	2/
31	Other Direct	261,702	81,689	
32	Total Gas	$10,473,658	$3,361,069	1/
33				2/
34				
35				
36				
37				
38				
39	TOTAL	$45,586,530	$10,992,407	

1/ Allocated to Montana.

2/ Directly assigned to Montana.

TRANSMISSION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2002

	Total Company			
		Peak Day of Month	Peak Day Volumes Mcf or Dkt	Total Monthly Volumes Mcf or Dkt
1	January			
2	February			
3	March			
4	April			
5	May			
6	June	**NOT APPLICABLE**		
7	July			
8	August			
9	September			
10	October			
11	November			
12	December			
13	**TOTAL**			

	Montana			
		Peak Day of Month	Peak Day Volumes Mcf or Dkt	Total Monthly Volumes Mcf or Dkt
14	January			
15	February			
16	March			
17	April			
18	May			
19	June	**NOT APPLICABLE**		
20	July			
21	August			
22	September			
23	October			
24	November			
25	December			
26	**TOTAL**			

DISTRIBUTION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2002

	Total Company			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
1	January	1	267,146	6,345,762
2	February	25	272,417	5,086,338
3	March	8	260,613	6,205,596
4	April	2	212,958	3,797,580
5	May	8	146,161	2,661,774
6	June	10	63,599	1,442,291
7	July	31	51,504	1,287,622
8	August	28	52,961	1,445,691
9	September	25	98,653	1,830,120
10	October	29	233,027	4,638,419
11	November	25	225,653	4,996,510
12	December	4	247,462	6,079,489
13	**TOTAL**			45,817,192

	Montana			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
14	January	1	86,173	1,930,015
15	February	25	82,724	1,564,008
16	March	20	79,961	1,892,933
17	April	1	61,492	1,186,167
18	May	7	44,687	796,761
19	June	10	21,158	414,365
20	July	31	17,936	345,445
21	August	28	20,727	488,038
22	September	27	39,248	650,801
23	October	29	75,568	1,555,799
24	November	25	70,373	1,587,206
25	December	4	75,927	1,921,419
26	**TOTAL**			14,332,957

Year: 2002

STORAGE SYSTEM - TOTAL COMPANY & MONTANA

		Total Company						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
1	January	13	28	9,896	145,460	19,603	2,381,894	
2	February	22	25	1,729	150,122	2,992	1,861,598	
3	March	26	8	1,227	148,655	6,876	2,638,572	
4	April	13	2	36,724	100,066	189,254	623,056	
5	May	31	8	54,811	38,743	738,693	170,353	
6	June	30	14	63,966	320	1,527,830	910	
7	July	13		74,059	0	2,178,334	0	
8	August	31		93,810	0	2,557,431	0	
9	September	17	21	81,900	1,717	2,110,921	7,513	
10	October	10	31	55,074	68,263	504,073	422,380	
11	November	7	25	7,623	88,751	56,301	1,074,148	
12	December	7	4	1,734	109,402	12,977	2,017,236	
13	**TOTAL**					9,905,285	11,197,660	

		Montana						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
14	January							
15	February							
16	March							
17	April							
18	May							
19	June	NOT AVAILABLE						
20	July							
21	August							
22	September							
23	October							
24	November							
25	December							
26	**TOTAL**							

SOURCES OF GAS SUPPLY

Year: 2002

	Name of Supplier 1/	Last Year Volumes Dkt	This Year Volumes Dkt	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2					
3					
4					
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24					
25					
26					
27					
28					
29	1/ Supplier information is proprietary and confidential.				
30					
31					
32					
33	**Total Gas Supply Volumes**	35,169,182	34,292,125	$3.468	$2.013

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 34

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2002

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings **(Mcf or Dkt)**	Achieved Savings **(Mcf or Dkt)**	Difference
1							
2	NONE						
3							
4							
5							
6							
7							
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30							
31							
32	**TOTAL**						

MONTANA CONSUMPTION AND REVENUES

Year: 2002

	Sales of Gas	Operating Revenues Current Year	Operating Revenues Previous Year	DK Sold Current Year	DK Sold Previous Year	Avg. No. of Customers Current Year	Avg. No. of Customers Previous Year
1	Residential	$29,528,787	$42,258,645	6,207,896	5,555,748	62,947	62,170
2	Firm General	16,549,060	24,776,761	3,634,551	3,329,228	7,631	7,588
3	Small Interruptible	306,359	429,798	82,413	73,969	4	4
4	Large Interruptible		298		10		
5							
6							
7							
8							
9							
10							
11	**TOTAL**	$46,384,206	$67,465,502	9,924,860	8,958,955	70,582	69,762
12							
13							

	Transportation of Gas	Operating Revenues Current Year	Operating Revenues Previous Year	BCF Transported Current Year	BCF Transported Previous Year	Avg. No. of Customers Current Year	Avg. No. of Customers Previous Year
18							
19	Utilities						
20	Small Interruptible	$468,141	$497,120	0.7	0.8	36	33
21	Large Interruptible	553,882	596,858	3.9	3.9	5	5
22	Firm		12,378				
23							
24	**TOTAL**	$1,022,023	$1,106,356	4.6	4.7	41	38